EDISON INTERNATIONAL
Form 10-Q
November 03, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2006

¨ **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 1-9936

EDISON INTERNATIONAL

(Exact name of registrant as specified in its charter)

California	**95-4137452**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
2244 Walnut Grove Avenue	**91770**

(P. O. Box 976)

Rosemead, California
(Address of principal executive offices) **(Zip Code)**
(626) 302-2222

(Registrant s telephone number, including area code)

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 x 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 in Rule 12b-2 of the Exchange Act.

Large accelerated filer x 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 x

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date:

Class	Outstanding at October 31, 2006
Common Stock, no par value	**325,811,206**

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

CONSOLIDATED STATEMENTS OF INCOME

In millions, except per-share amounts	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
		(Unaudited)		
Electric utility	**$ 3,079**	$ 3,084	**$ 7,818**	$ 7,194
Nonutility power generation	**704**	677	**1,674**	1,605
Financial services and other	**19**	22	**63**	79
Total operating revenue	**3,802**	3,783	**9,555**	8,878
Fuel	**486**	489	**1,326**	1,309
Purchased power	**1,036**	502	**2,819**	1,633
Provisions for regulatory adjustment clauses net	**115**	766	**(256)**	790
Other operation and maintenance	**853**	862	**2,561**	2,497
Depreciation, decommissioning and amortization	**293**	270	**924**	796
Property and other taxes	**56**	51	**166**	153
Net gain on sale of utility property and plant			**(1)**	
Total operating expenses	**2,839**	2,940	**7,539**	7,178
Operating income	**963**	843	**2,016**	1,700
Interest and dividend income	**41**	31	**120**	78
Equity in income from partnerships and unconsolidated subsidiaries net	**39**	27	**53**	136
Other nonoperating income	**16**	34	**91**	70
Interest expense net of amounts capitalized	**(199)**	(198)	**(608)**	(615)
Impairment loss on equity method investment		(55)		(55)
Loss on early extinguishment of debt			**(143)**	(24)
Other nonoperating deductions	**(13)**	(35)	**(35)**	(58)
Income from continuing operations before income tax and minority interest	**847**	647	**1,494**	1,232
Income tax	**310**	129	**516**	267
Dividends on utility preferred and preference stock not subject to mandatory redemption	**13**	7	**38**	14
Minority interest	**64**	76	**123**	142
Income from continuing operations	**460**	435	**817**	809
Income (loss) from discontinued operations net of tax	**(2)**	27	**75**	55
Income before accounting change	**458**	462	**892**	864
Cumulative effect of accounting change net of tax			**1**	
Net income	**$ 458**	$ 462	**$ 893**	$ 864
Weighted-average shares of common stock outstanding	**326**	326	**326**	326
Basic earnings (loss) per common share:				
Continuing operations	**$ 1.39**	$ 1.33	**$ 2.48**	$ 2.47
Discontinued operations	**(0.01)**	0.08	**0.23**	0.17
Total	**$ 1.38**	$ 1.41	**$ 2.71**	$ 2.64
Weighted-average shares, including effect of dilutive securities	**330**	332	**331**	331
Diluted earnings (loss) per common share:				
Continuing operations	**$ 1.39**	$ 1.31	**$ 2.48**	$ 2.45
Discontinued operations	**(0.01)**	0.08	**0.23**	0.16
Total	**$ 1.38**	$ 1.39	**$ 2.71**	$ 2.61

Dividends declared per common share	**$ 0.27**	$ 0.25	**$ 0.81**	$ 0.75

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

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In millions	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(Unaudited)			
Net income	**$ 458**	$ 462	**$ 893**	$ 864
Other comprehensive income (loss), net of tax:				
Foreign currency translation adjustments	**(3)**	1	**(1)**	(1)
Minimum pension liability adjustment			**(2)**	
Unrealized gain (loss) on cash flow hedges:				
Other unrealized gain (loss) on cash flow hedges net	**94**	(164)	**352**	(218)
Reclassification adjustment for loss included in net income	**(11)**	(72)	**(23)**	(80)
Other comprehensive income (loss)	**80**	(235)	**326**	(299)
Comprehensive income	**$ 538**	$ 227	**$ 1,219**	$ 565

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

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CONSOLIDATED BALANCE SHEETS

In millions	September 30, 2006 (Unaudited)	December 31, 2005
ASSETS		
Cash and equivalents	**$ 2,204**	$ 1,893
Restricted cash	**64**	60
Margin and collateral deposits	**234**	739
Receivables, less allowances of $29 and $33 for uncollectible accounts at respective dates	**1,387**	1,220
Accrued unbilled revenue	**426**	291
Fuel inventory	**138**	80
Materials and supplies	**263**	261
Accumulated deferred income taxes net	**306**	218
Trading and price risk management assets	**290**	316
Regulatory assets	**556**	536
Short-term investments	**366**	211
Other current assets	**129**	134
Total current assets	**6,363**	5,959
Nonutility property less accumulated provision for depreciation of $1,576 and $1,424 at respective dates	**4,190**	4,119
Nuclear decommissioning trusts	**3,061**	2,907
Investments in partnerships and unconsolidated subsidiaries	**365**	426
Investments in leveraged leases	**2,480**	2,447
Other investments	**100**	115
Total investments and other assets	**10,196**	10,014
Utility plant, at original cost:		
Transmission and distribution	**17,212**	16,760
Generation	**1,458**	1,370
Accumulated provision for depreciation	**(4,710)**	(4,763)
Construction work in progress	**1,331**	956
Nuclear fuel, at amortized cost	**170**	146
Total utility plant	**15,461**	14,469
Regulatory assets	**2,774**	3,013
Restricted cash	**116**	105
Margin and collateral deposits	**29**	137
Trading and price risk management assets	**205**	132
Other long-term assets	**1,147**	951
Total long-term assets	**4,271**	4,338
Assets of discontinued operations		11
Total assets	**$ 36,291**	$ 34,791

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

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EDISON INTERNATIONAL

CONSOLIDATED BALANCE SHEETS

In millions, except share amounts	September 30, 2006 (Unaudited)	December 31, 2005
LIABILITIES AND SHAREHOLDERS EQUITY		
Long-term debt due within one year	$ 371	$ 745
Accounts payable	819	961
Accrued taxes	843	262
Accrued interest	201	212
Counterparty collateral	32	183
Customer deposits	191	183
Book overdrafts	227	257
Trading and price risk management liabilities	252	418
Regulatory liabilities	1,287	681
Other current liabilities	793	1,057
Total current liabilities	5,016	4,959
Long-term debt	8,983	8,833
Accumulated deferred income taxes net	5,370	5,256
Accumulated deferred investment tax credits	125	130
Customer advances and other deferred credits	1,125	1,179
Trading and price risk management liabilities	188	101
Power-purchase contracts	39	64
Accumulated provision for pensions and benefits	831	745
Asset retirement obligations	2,687	2,628
Regulatory liabilities	2,880	2,962
Other long-term liabilities	290	285
Total deferred credits and other liabilities	13,535	13,350
Liabilities of discontinued operations		14
Total liabilities	27,534	27,156
Commitments and contingencies (Notes 3 and 4)		
Minority interest	304	301
Preferred and preference stock of utility not subject to mandatory redemption	915	719
Common stock, no par value (325,811,206 shares outstanding at each date)	2,058	2,043
Accumulated other comprehensive income (loss)	100	(226)
Retained earnings	5,380	4,798
Total common shareholders equity	7,538	6,615
Total liabilities and shareholders equity	$ 36,291	$ 34,791

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
In millions	2006	2005 Revised(1)
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 893	$ 864
Less: income from discontinued operations net of tax	75	55
Income from continuing operations	818	809
Adjustments to reconcile to net cash provided by operating activities:		
Cumulative effect of accounting change net of tax	(1)	
Depreciation, decommissioning and amortization	924	796
Other amortization	71	81
Minority interest	123	142
Deferred income taxes and investment tax credits	(154)	(239)
Equity in income from partnerships and unconsolidated subsidiaries	(53)	(136)
Income from leveraged leases	(52)	(54)
Regulatory assets long-term	117	372
Regulatory liabilities long-term	(151)	(92)
Loss on early extinguishment of debt	143	24
Impairment losses		67
Levelized rent expense	(160)	(115)
Other assets	(163)	(101)
Other liabilities	144	105
Margin and collateral deposits net of collateral received	462	(413)
Receivables and accrued unbilled revenue	(286)	(560)
Trading and price risk management assets short-term	204	(410)
Inventory and other current assets	(35)	(7)
Regulatory assets short-term	(20)	7
Regulatory liabilities short-term	606	773
Accrued interest and taxes	562	477
Accounts payable and other current liabilities	(230)	139
Distributions and dividends from unconsolidated entities	19	40
Operating cash flows from discontinued operations	82	22
Net cash provided by operating activities	2,970	1,727
Cash flows from financing activities:		
Long-term debt issued and issuance costs	1,868	1,143
Long-term debt repaid	(2,090)	(1,883)
Issuance of preference stock	196	592
Redemption of preferred stock		(148)
Rate reduction notes repaid	(177)	(177)
Short-term debt financing net		(88)
Change in book overdrafts	(31)	39
Shares purchased for stock-based compensation	(124)	(145)
Proceeds from stock option exercises	45	78
Excess tax benefits related to stock option exercises	18	
Dividends to minority shareholders	(114)	(122)
Dividends paid	(264)	(244)
Net cash used by financing activities	$ (673)	$ (955)

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

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Nine Months Ended September 30, 2006	2005 Revised(1)
	(Unaudited)	
Cash flows from investing activities:		
Capital expenditures	**$ (1,757)**	$ (1,337)
Purchase of interest of acquired companies	**(18)**	
Proceeds from sale of property and interests in projects	**43**	
Proceeds from sale of discontinued operations		124
Proceeds from nuclear decommissioning trust sales	**2,145**	1,581
Purchases of nuclear decommissioning trust investments	**(2,253)**	(1,657)
Proceeds from return of capital	**53**	92
Maturities and sales of short-term investments	**121**	140
Purchase of short-term investments	**(305)**	
Restricted cash	**(10)**	84
Turbine deposits	**(54)**	
Customer advances for construction and other investments	**49**	82
Investing cash flows from discontinued operations		5
Net cash used by investing activities	**(1,986)**	(886)
Effect of consolidation of variable interest entities on cash		3
Effect of exchange rate changes on cash		(1)
Net increase (decrease) in cash and equivalents	**311**	(112)
Cash and equivalents, beginning of period	**1,893**	2,689
Cash and equivalents, end of period	**2,204**	2,577
Cash and equivalents, discontinued operations		(2)
Cash and equivalents, continuing operations	**$ 2,204**	$ 2,575

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Management s Statement

In the opinion of management, all adjustments, including recurring accruals, have been made that are necessary for a fair statement of the financial position, results of operations and cash flows in accordance with accounting principles generally accepted in the United States for the periods covered by this quarterly report on Form 10-Q. The results of operations for the period ended September 30, 2006 are not necessarily indicative of the operating results for the full year.

This quarterly report should be read in conjunction with Edison International s Annual Report on Form 10-K for the year ended December 31, 2005 filed with the Securities and Exchange Commission.

Note 1. Summary of Significant Accounting Policies

Basis of Presentation

Edison International s significant accounting policies were described in Note 1 of Notes to Consolidated Financial Statements included in its 2005 Annual Report. Edison International follows the same accounting policies for interim reporting purposes, with the exception of the change in accounting for stock-based compensation (discussed below in New Accounting Pronouncements).

On April 1, 2006, Edison Mission Energy (EME) received, as a capital contribution from its affiliate, Edison Capital, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. EME accounted for this acquisition at Edison Capital s historical cost as a transaction between entities under common control. As a result of this capital contribution, Edison International s nonutility power generation segment now includes the wind assets and biomass power project previously owned by Edison Capital.

Certain prior-period amounts were reclassified to conform to the September 30, 2006 financial statement presentation. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

Debt and Equity Investments

At September 30, 2006, EME s short-term investments consisting of held-to-maturity securities which mature within one year are $295 million of commercial paper, $67 million of certificates of deposit and $4 million of corporate bonds.

Derivative Instruments and Hedging Activities

Edison International uses derivative financial instruments to manage financial exposure on its investments and fluctuations in commodity prices, interest rates, foreign currency exchange rates, and emission and transmission rights. Edison International manages these risks in part by entering into interest rate swap, cap and lock agreements, and forward commodity transactions, including options, swaps and futures. Edison International has a power marketing and trading subsidiary that markets the energy and capacity of EME s merchant generating fleet and, in addition, trades electric power and energy and related commodity and financial products.

Edison International records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. Financial instruments that are utilized for trading purposes are included in the consolidated balance sheets as assets or liabilities from trading and price risk management activities. The normal purchases and sales exception requires, among other things, physical delivery in quantities

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

expected to be used or sold over a reasonable period in the normal course of business. Gains and losses from changes in the fair value of a recognized asset liability or a firm commitment are reflected in earnings for the ineffective portion of a designated hedge. For a designated hedge of the cash flows of a forecasted transaction or a foreign currency exposure, the effective portion of the gain or loss is initially recorded as a separate component of shareholders equity under the caption accumulated other comprehensive income, and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately. Hedge accounting requires Edison International to formally document, designate, and assess the effectiveness of hedge transactions.

Fair value changes for EME s trading operations are reflected in earnings. Southern California Edison Company s (SCE) derivative transactions are pre-approved by the California Public Utilities Commission (CPUC) or executed in compliance with CPUC-approved procurement plans. SCE s derivative instrument fair values are marked to market at each reporting period. Any fair value changes for these recorded derivatives are recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses; therefore, fair value changes do not affect earnings. Hedge accounting is not used for these transactions due to this regulatory accounting treatment.

SCE recorded net unrealized losses of $9 million and $351 million, for the three- and nine-month periods ended September 30, 2006, respectively, compared to net unrealized gains of $504 million and $457 million, for the same periods in 2005, respectively.

Earnings Per Common Share (EPS)

Edison International computes EPS using the two-class method, which is an earnings allocation formula that determines EPS for each class of common stock and participating security. Edison International s participating securities are vested stock options that earn dividend equivalents on an equal basis with common shares. The number of participating shares increased in 2006, as stock options awarded since 2003 received dividend equivalents. Stock options from 2000 through 2002 were granted without a dividend equivalent feature. As the awards since 2003 vest, the number of participating shares increases. Further, the 1998 and 1999 options did not earn dividend equivalents until 2006, when performance criteria were triggered.

Basic EPS is computed by dividing net income available for common stock by the weighted-average number of common shares outstanding. Net income available for common stock was $451 million and $459 million for the three months ended September 30, 2006, and 2005, respectively, and was $882 million and $859 million for the nine months ended September 30, 2006, and 2005, respectively. In arriving at net income, dividends on preferred and preference stock have been deducted.

For the diluted EPS calculation, dilutive securities (stock-based compensation awards exercisable) are added to the weighted-average shares. Dilutive securities are excluded from the diluted EPS calculation for items with a net loss due to their antidilutive effect.

Income Taxes

Edison International s effective tax rate from continuing operations was 40% and 39% for the three- and nine-month periods ended September 30, 2006, respectively, as compared to 23% and 25% for the same periods in 2005. The increased effective tax rate resulted primarily from recording a $65 million benefit, including $57 million of interest income, in the third quarter of 2005 related to a settlement with the Internal Revenue Service (IRS) on tax issues and pending affirmative claims relating to Edison International s 1991 1993 tax

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years. Additional increases to the effective tax rate resulted from reductions made to SCE s income tax reserve in 2005 to reflect the issuance of new IRS regulations and progress in settlement negotiations relating to tax audits other than the 1991 1993 IRS audit, and adjustments made to tax balances in 2005 at both Mission Energy Holding Company (MEHC) and SCE.

New Accounting Pronouncements

A new accounting standard, Statement of Financial Accounting Standards (SFAS) No. 123(R), requires companies to use the fair value accounting method for stock-based compensation. Edison International 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, Edison International used the intrinsic value method of accounting, which resulted in no recognition of expense for its stock options. Prior to adoption of the new accounting standard, Edison International presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption Other 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 $18 million excess tax benefit is classified as a financing cash inflow in 2006. Due to the adoption of this new accounting standard, Edison International recorded a cumulative effect adjustment that increased net income by approximately $1 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.

In April 2006, the Financial Accounting Standards Board (FASB) issued a Staff Position (FSP), FSP FIN 46(R)-6, that specifies how a company should determine the variability to be considered in applying the accounting standard for consolidation of variable interest entities. The pronouncement states that such variability shall be determined based on an analysis of the design of the entity, including the nature of the risks in the entity, the purpose for which the entity was created, and the variability the entity is designed to create and pass along to its interest holders. This new accounting guidance was effective prospectively beginning July 1, 2006, although companies have until December 31, 2006, to elect retrospective application. Edison International has not yet selected a transition method. Applying the guidance of FSP FIN 46(R)-6 had no effect on the financial statements for the three months ended September 30, 2006.

In July 2006, the FASB issued an interpretation (FIN 48) relating to accounting for uncertainty in income taxes. This interpretation 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 is January 1, 2007. Edison International is currently assessing the potential impact of FIN 48 on its financial condition.

In July 2006, the FASB issued an FSP on accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction (FSP FAS 13-2). The effective date is January 1, 2007. As discussed under Federal and State Income Taxes in Note 3, the deferral of income taxes associated with Edison Capital s cross-border, leveraged leases has been challenged by the IRS. If it becomes probable that Edison International would accelerate the payment of deferred taxes for these leases, the new FSP requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

In September 2006, the FASB issued a new accounting standard on fair value measurements (SFAS 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. Edison International will adopt SFAS No. 157 on January 1, 2008. Edison International is currently evaluating the impact of adopting SFAS No. 157 on its financial statements.

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 its balance sheet; the asset or liability is offset through other comprehensive income. Edison International will record regulatory assets or liabilities instead of charges or credits to other comprehensive income for its postretirement benefit plans that are recoverable in utility rates, in accordance with accounting principles for rate-regulated enterprises. The standard also requires companies to align the measurement dates for their plans to their fiscal year-ends; Edison International already has a fiscal year-end measurement date for all of its postretirement plans. Edison International will adopt SFAS No. 158 prospectively on December 31, 2006. Had SFAS No. 158 been effective as of December 31, 2005, Edison International would have recorded additional postretirement benefit liabilities of $773 million, additional regulatory assets of $723 million, and a reduction to accumulated other comprehensive income (a component of shareholders equity) of $31 million, net of tax. Edison International is currently assessing the impact of this standard on its 2006 financial statements.

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. The new guidance requires additional quantitative testing to determine whether a misstatement is material. Edison International will implement SAB No. 108 for the filing of its Annual Report on Form 10-K for the year ended December 31, 2006. Edison International is currently assessing the impact, if any, of the adoption of SAB No. 108.

In September 2006, the FASB s Emerging Issues Task Force (EITF) reached a consensus for Issue No. 06-5, which clarifies the accounting for purchases of life insurance, including corporate-owned life insurance. The new guidance states that policyholders should consider any additional amounts included in the contractual terms of the policy in determining the amount that could be realized under the insurance contract, and specifies that contractual limitations should be considered when determining the realizable amounts. The new guidance is effective January 1, 2007, and retrospective application or a cumulative effect adjustment is permitted to transition to the new guidance. Edison International is currently evaluating the impact, if any, of adopting EITF Issue No. 06-5.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

Regulatory assets included in the consolidated balance sheets are:

In millions	September 30, 2006 (Unaudited)	December 31, 2005
Current:		
Regulatory balancing accounts	**$ 294**	$ 355
Direct access procurement charges	**85**	113
Energy derivatives	**110**	
Purchased-power settlements	**32**	53
Other	**35**	15
	556	536
Long-term:		
Flow-through taxes net	**1,022**	1,066
Rate reduction notes transition cost deferral	**275**	465
Unamortized nuclear investment net	**444**	487
Nuclear-related asset retirement obligation investment net	**280**	292
Unamortized coal plant investment net	**109**	97
Unamortized loss on reacquired debt	**315**	323
Direct access procurement charges		40
Energy derivatives	**143**	58
Environmental remediation	**85**	56
Purchased-power settlements	**15**	39
Other	**86**	90
	2,774	3,013
Total regulatory assets	**$ 3,330**	$ 3,549

Regulatory liabilities included in the consolidated balance sheets are:

In millions	September 30, 2006 (Unaudited)	December 31, 2005
Current:		
Regulatory balancing accounts	**$ 1,089**	$ 370
Direct access procurement charges	**85**	113
Energy derivatives		136
Other	**113**	62
	1,287	681
Long-term:		
Asset retirement obligations	**650**	584
Costs of removal	**2,142**	2,110
Direct access procurement charges		39

Employee benefit plans		**88**		229
		2,880		2,962
Total regulatory liabilities	**$**	**4,167**	$	3,643

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revisions

Edison International revised its consolidated statements of cash flows for the nine months ended September 30, 2005 to separately disclose the operating, financing and investing portions of the cash flows attributable to discontinued operations consistent with its consolidated statements of cash flow for the year ended December 31, 2005 included in Edison International s Annual report on Form 10-K for the year ended December 31, 2005. Edison International had previously reported these amounts on a combined basis in its quarterly report on Form 10-Q for the quarter ended September 30, 2005.

Stock-Based Compensation

Edison International s stock-based compensation plans primarily include the issuance of 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 earned. 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 2.

Prior to January 1, 2006, Edison International 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. Previously, Edison International did not capitalize stock-based compensation cost related to both unvested awards and new awards. As discussed in New Accounting Pronouncements above, effective January 1, 2006, Edison International 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. Edison International recognizes stock-based compensation expense on a straight-line basis over the vesting period. Edison International is capitalizing a portion of its stock-based compensation cost related to both unvested awards and new awards. Edison International recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, Edison International 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 will be 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 Edison International 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 expense would have decreased $2 million for the quarter ended September 30, 2006, would have increased $3 million for the quarter ended September 30, 2005, would have decreased $5 million for the nine months ended September 30, 2006 and would have increased $7 million for the nine months ended September 30, 2005.

Total stock-based compensation expense (reflected in the caption Other operation and maintenance on the consolidated statements of income) was $14 million and $30 million for the three months ended September 30, 2006 and 2005, respectively, and was $37 million and $75 million for the nine months ended September 30, 2006 and 2005, respectively. The income tax benefit recognized in the income statement was $6 million and $12 million for the three months ended September 30, 2006 and 2005, respectively, and was $15 million and $30 million for the nine months ended September 30, 2006 and 2005, respectively. Total stock-based

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compensation cost capitalized for the three and nine months ended September 30, 2006, was $2 million and $4 million, respectively.

The following table illustrates the effect on net income and EPS if Edison International had used the fair-value accounting method for the quarter and nine months ended September 30, 2005.

In millions, except per-share amounts	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
	(Unaudited)	
Net income, as reported	$ 462	$ 864
Add: stock-based compensation expense using the intrinsic value accounting method net of tax	18	44
Less: stock-based compensation expense using the fair-value accounting method net of tax	14	37
Pro forma net income	$ 466	$ 871
Basic EPS:		
As reported	$ 1.41	$ 2.64
Pro forma	$ 1.42	$ 2.66
Diluted EPS:		
As reported	$ 1.39	$ 2.61
Pro forma	$ 1.41	$ 2.64

Supplemental Accumulated Other Comprehensive Loss Information

Supplemental information regarding Edison International s accumulated other comprehensive loss is:

In millions	September 30, 2006	December 31, 2005
	(Unaudited)	
Foreign currency translation adjustments net of tax	**$**	$ 2
Minimum pension liability net of tax	**(14)**	(12)
Unrealized gain (loss) on cash flow hedges net of tax	**114**	(216)
Accumulated other comprehensive income (loss)	**$ 100**	$ (226)

The minimum pension liability is discussed in Note 6, Compensation and Benefit Plans of Notes to Consolidated Financial Statements included in Edison International s 2005 Annual Report.

Included in Edison International s accumulated other comprehensive income at September 30, 2006, was a $114 million gain related to EME s net unrealized gains on cash flow hedges.

Unrealized gains on cash flow hedges at September 30, 2006, include unrealized gains on commodity hedges related to EME s Homer City and Midwest Generation 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.

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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. EME expects that reclassification of the 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 an EME 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 nonutility power generation revenue on Edison International s consolidated statements of income.

Supplemental Cash Flows Information

In millions	Nine Months Ended September 30, **2006**	2005
	(Unaudited)	
Cash payments for interest and taxes:		
Interest net of amounts capitalized	**$ 539**	$ 576
Tax payments	**155**	62
Noncash investing and financing activities:		
Details of debt exchange:		
Pollution-control bonds redeemed	**$ 331**	$ (452)
Pollution-control bonds issued	**(331)**	452
Funds held in trust		
Dividends declared but not paid	**$ 88**	$ 81
Details of assets acquired:		
Fair value of assets acquired	**$ 29**	
Liabilities assumed		
Liabilities accrued	**11**	

Note 2. Compensation and Benefits Plans

Pension Plans

Edison International previously disclosed in Note 6 of Notes to Consolidated Financial Statements included in Edison International s 2005 Annual Report that it expects to contribute approximately $66 million to its pension plans in 2006. As of September 30, 2006, $44 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.

Net pension cost recognized is calculated under the actuarial method used for ratemaking. The difference between pension costs calculated for accounting and ratemaking is deferred.

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Expense components are:

In millions	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
		(Unaudited)		
Service cost	**$ 31**	$ 29	**$ 91**	$ 87
Interest cost	**45**	43	**136**	129
Expected return on plan assets	**(58)**	(55)	**(175)**	(167)
Special termination benefits	**4**		**8**	
Net amortization and deferral	**5**	6	**16**	20
Expense under accounting standards	**27**	23	**76**	69
Regulatory adjustment deferred	**(2)**	(2)	**(5)**	(6)
Total expense recognized	**$ 25**	$ 21	**$ 71**	$ 63

Due to the Mohave Generating Station (Mohave) shutdown, SCE has incurred costs for special termination benefits. See Mohave Shutdown in Note 8 for further information.

Postretirement Benefits Other Than Pensions

Edison International previously disclosed in Note 6 of Notes to Consolidated Financial Statements included in Edison International s 2005 Annual Report that it expects to contribute approximately $79 million to its postretirement benefits other than pension plans in 2006. As of September 30, 2006, $19 million in contributions have been made. Edison International anticipates that its original expectation will be met by year-end 2006.

Expense components are:

In millions	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
		(Unaudited)		
Service cost	**$ 12**	$ 12	**$ 37**	$ 36
Interest cost	**31**	31	**95**	93
Expected return on plan assets	**(27)**	(26)	**(81)**	(77)
Special termination benefits	**3**		**6**	
Amortization of unrecognized prior service costs	**(7)**	(7)	**(23)**	(22)
Amortization of unrecognized loss	**12**	12	**36**	36
Total expense	**$ 24**	$ 22	**$ 70**	$ 66

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits. See Mohave Shutdown in Note 8 for further information.

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Stock-Based Compensation

Stock Options

Under various plans, Edison International may grant stock options at exercise prices equal to the average of the high and low price at the grant date and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the vesting period, except for awards granted to retirement-eligible participants, as discussed in Stock-Based Compensation in Note 1. Stock-based compensation associated with stock options (including amounts capitalized) was $10 million for the three months ended September 30, 2006 and $30 million for the nine months ended September 30, 2006. Under prior accounting rules, there was no comparable expense recognized for the same periods in 2005. See Stock-Based Compensation in Note 1 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 nonqualified deferral plan accounts, dividend equivalents accumulate without interest. Dividend equivalents are paid only on options that vest, including options that are unexercised. Dividend equivalents are paid in cash after the vesting date. Edison International has discretion to pay certain dividend equivalents in shares of Edison International common stock. Additionally, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

The fair value for each option granted was determined as of the 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
	(Unaudited)			
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.

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A summary of the status of Edison International stock options is as follows:

	Stock Options	Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
		(Unaudited)		
Outstanding at December 31, 2005	15,331,659	$ 22.99		
Granted	2,012,176	$ 44.10		
Expired				
Forfeited	(72,561)	$ 30.68		
Exercised	(2,133,397)	$ 21.14		
Outstanding at September 30, 2006	15,137,877	$ 26.01		
Vested and expected to vest at September 30, 2006	14,521,759	$ 25.79	6.40	$ 226,975,093
Exercisable at September 30, 2006	8,061,177	$ 21.81	5.06	$ 158,079,681

The weighted-average grant-date fair value of options granted during the quarters ended September 30, 2006 and 2005, was $13.70 and $14.24, respectively. The weighted-average grant-date fair value of options granted during the nine months ended September 30, 2006 and 2005, was $14.42 and $11.79, respectively. The total intrinsic value of options exercised during the quarters ended September 30, 2006 and 2005, was $11 million and $28 million, respectively. The total intrinsic value of options exercised during the nine months ended September 30, 2006 and 2005, was $46 million and $67 million, respectively. At September 30, 2006, there was $44 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 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 $5 million and $7 million, respectively.

The amount of cash used to settle stock options exercised was $23 million and $54 million for the quarters ended September 30, 2006 and 2005, respectively, and $91 million and $145 million for the nine months ended September 30, 2006 and 2005, respectively. Cash received from options exercised for the quarters ended September 30, 2006 and 2005, was $12 million and $26 million, respectively, and for the nine months ended September 30, 2006 and 2005, was $45 million and $78 million, respectively. The estimated tax benefit from options exercised for the nine months ended September 30, 2006 and 2005, was $18 million and $26 million, 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

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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. Stock-based compensation associated with performance shares (including amounts capitalized) was $5 million and $25 million for the three months ended September 30, 2006 and 2005, respectively, and $9 million and $58 million for the nine months ended September 30, 2006 and 2005, respectively. The amount of cash used to settle performance shares classified as equity awards was zero for both the quarters ended September 30, 2006 and 2005, and $37 million and $20 million 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 semi-annual coupon U.S. Treasury note and is used as proxy for the expected return for the specified group of companies. Volatility is based on the historical volatility of Edison International s common stock for the recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

Edison International s risk-free interest rate 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 $73 million and $40 million, respectively, which included cash paid to settle the performance shares classified as liability awards for the nine months ended September 30, 2006 and 2005 of $24 million and $13 million, respectively. At September 30, 2006, there was $9 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 value of performance shares vested during the quarters ended September 30, 2006 and 2005 was zero. The fair value of performance shares vested during the nine-month periods ended September 30, 2006 and 2005, was less than $1 million and zero, respectively.

A summary of the status of Edison International nonvested performance shares classified as equity awards is as follows:

	Performance Shares		Weighted-Average Grant-Date Fair Value
		(Unaudited)	
Nonvested at December 31, 2005	280,289	$	39.19
Granted	83,008	$	52.90
Forfeited	(4,599)	$	39.41
Paid out	(5,057)	$	39.77
Nonvested at September 30, 2006	353,641	$	42.40

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

A summary of the status of Edison International nonvested performance shares classified as liability awards (the current portion is reflected in the caption Other current liabilities and the long-term portion is reflected in Accumulated provision for pensions and benefits on the consolidated balance sheets) is as follows:

	Performance Shares	Weighted-Average Fair Value
	(Unaudited)	
Nonvested at December 31, 2005	280,434	
Granted	83,096	
Forfeited	(4,605)	
Paid out	(5,058)	
Nonvested at September 30, 2006	353,867	$ 82.63

Note 3. Contingencies

In addition to the matters disclosed in these Notes, Edison International is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. Edison International believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

2006 General Rate Case (GRC) Proceeding

In December 2004, SCE filed its application for a 2006 GRC and subsequently revised its requested 2006 base rate revenue requirement to $3.96 billion, an increase of $465 million over SCE s 2005 base rate revenue. When a one-time credit of $140 million from an existing balancing account overcollection was applied, SCE s requested increase was $325 million. SCE also proposed revised base rate revenue increases of $108 million for 2007 and $113 million for 2008.

On May 11, 2006, the CPUC issued its final decision authorizing an increase of $274 million over SCE s 2005 base rate revenue, retroactive to January 12, 2006. When the one-time credit of $140 million from an existing balancing account overcollection was applied, SCE s authorized increase was $134 million. The CPUC also authorized increases of $74 million in 2007 and $104 million in 2008. The decision substantially approved SCE s request to continue its capital investment program for infrastructure replacement and expansion, with authorized revenue in excess of costs for this program subject to refund. In addition, the decision provided for balancing accounts for pensions, postretirement medical benefits and certain incentive compensation expense.

During the second quarter of 2006, SCE implemented the 2006 GRC decision and resolved an outstanding regulatory issue which resulted in a pre-tax benefit of approximately $175 million. The implementation of the 2006 GRC decision retroactive to January 12, 2006 mainly resulted in revenue of $50 million related to the revenue requirement for the period January 12, 2006 through May 31, 2006, partially offset by the implementation of the new depreciation rates resulting in increased depreciation expense of approximately $25 million for the period January 12, 2006 through May 31, 2006. In addition, there was a favorable resolution of a one-time issue related to a portion of revenue collected during the 2001 2003 period for state income taxes. SCE was able to determine through regulatory proceedings (including the 2006 GRC decision) that the level of revenue collected during that period was appropriate, and as a result recorded a pre-tax gain of $135 million.

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Environmental Remediation

Edison International is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

Edison International believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that Edison International s financial position and results of operations would not be materially affected.

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

Edison International s recorded estimated minimum liability to remediate its 35 identified sites at SCE (23 sites) and EME (12 sites related to Midwest Generation) is $87 million, $84 million of which is related to SCE. Edison International s other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International s identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $116 million, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 32 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $8 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $35 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $85 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International s identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that Edison International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

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Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $25 million. Recorded costs for the twelve months ended September 30, 2006 were $13 million.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC s regulatory treatment of environmental remediation costs incurred at SCE, Edison International believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 1996 and 1997 1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would be deductible on future tax returns of Edison International. Edison International has also submitted affirmative claims to the IRS and state tax agencies which are being addressed in administrative proceedings. Any benefits would be recorded when a settlement is reached or as part of the implementation of FIN 48.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes associated with Edison Capital s cross-border, leveraged leases.

The IRS is challenging Edison Capital s foreign power plant and electric locomotive sale/leaseback transactions entered into in 1993 and 1994 (Replacement Leases, which the IRS refers to as a sale-in/lease-out or SILO). The IRS is also challenging Edison Capital s foreign power plant and electric transmission system lease/leaseback transactions entered into in 1997 and 1998 (Lease/Leaseback, which the IRS refers to as a lease-in/lease-out or LILO).

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (Service Contract, which the IRS also refers to as a SILO). The IRS did not yet assert an adjustment for the Service Contract but is expected to challenge the Service Contract in subsequent audit cycles.

The following table summarizes estimated federal and state income taxes deferred from these leases. Repayment of these deferred taxes would be accelerated if the IRS prevails:

	Tax Years Under Appeal	Unaudited Tax Years	
In millions	1994 1999	2000 2005	Total
Replacement Leases (SILO)	$ 44	$ 36	$ 80
Lease/Leaseback (LILO)	558	570	1,128
Service Contract (SILO)		272	272
	$ 602	$ 878	$ 1,480

As of September 30, 2006, the interest on the proposed tax adjustments is estimated to be approximately $386 million. The IRS also seeks a 20% penalty on any sustained tax adjustment.

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Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into, and it is vigorously defending its tax treatment of these leases. Written protests were filed to appeal the audit adjustments for the tax years under appeal asserting that the IRS s position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS.

In addition, the payment of taxes, interest and penalties could have a significant impact on earnings and cash flow. In order to commence litigation in certain forums, Edison International must make payments of disputed taxes, along with interest and any penalties asserted by the IRS, and thereafter pursue refunds. On May 26, 2006, Edison International paid $111 million of the taxes, interest and penalties for tax year 1999 followed by a refund claim for the same amount. The cash payment was funded by Edison Capital and accounted for as a deposit which will be refunded with interest to the extent Edison International prevails. If the IRS either denies this refund claim or fails to act on the claim within six months, Edison International expects to take legal action to assert its refund claim. Depending on the status of the claim for tax year 1999, Edison International may make additional payments related to other tax years to preserve its litigation rights, although, at this time, the amount and timing of these additional payments is uncertain. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters.

Under an FSP on accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction and a FASB interpretation relating to accounting for uncertainty in income taxes, both issued in July 2006 and effective January 1, 2007, the payments made by Edison International will continue to be treated as a deposit unless it becomes more likely than not that a tax payment related to the resolution of the dispute will be made. If it becomes probable that such a tax payment will be made, the new FSP requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

The IRS Revenue Agent Report for the 1997 1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged lease transactions and the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

Federal Energy Regulatory Commission (FERC) Notice Regarding Investigatory Proceeding against Edison Mission Marketing & Trading (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

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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.

FERC Refund Proceedings

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the California Power Exchange (PX) and California Independent System Operator (ISO) markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000 2001 and describing many of the techniques and effects of that market manipulation. SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets or who benefited from the manipulation by receiving inflated market prices. SCE is required to refund to customers 90% of any refunds actually realized by SCE net of litigation costs, except for the El Paso Natural Gas Company settlement agreement (see discussion in Note 9 of Notes to Consolidated Financial Statements in Edison International s 2005 Annual Report), and 10% will be retained by SCE as a shareholder incentive.

During the course of the refund proceedings, the FERC ruled that governmental power sellers, like private generators and marketers that sold into the California market, should refund the excessive prices they received during the crisis period. However, on September 21, 2005, the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) ruled that the FERC does not have authority directly to enforce its refund orders against governmental power sellers. The Court, however, clarified that its decision does not preclude SCE or other parties from pursuing civil claims against the governmental power sellers. On March 16, 2006, SCE, Pacific Gas and Electric Company (PG&E) and the California Electricity Oversight Board jointly filed suit in federal court against several governmental power sellers, seeking refunds based on the reduced prices set by the FERC for transactions during the crisis period. SCE cannot predict whether it may be able to recover any additional refunds from governmental power sellers as a result of this suit.

In November 2005, SCE and other parties entered into a settlement agreement with Enron Corporation and a number of its affiliates, most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In April 2006, SCE received an additional distribution on its allowed bankruptcy claim of approximately $29 million, and 196,245 shares of common stock of Portland General Electric Company with an aggregate value of approximately $5 million. In October 2006, SCE received another distribution on its allowed bankruptcy claim of approximately $20 million and 17,040 shares of Portland General Electric Company stock, with an aggregate value of less than $1 million. Additional distributions are expected but SCE cannot currently predict the amount or timing of such distributions.

In December 2005, the FERC approved a settlement agreement among SCE, PG&E, San Diego Gas & Electric, several governmental entities and certain other parties, and Reliant Energy, Inc. and a number of its affiliates. In March 2006, SCE received an additional $61 million as part of the settlement.

On August 2, 2006, the Ninth Circuit issued an opinion regarding the scope of refunds issued by the FERC. The Ninth Circuit widened the time period during which refunds could be issued to include the summer of 2000 for tariff violations and broadened the categories of transactions that could be subject to refund. As a result of this decision, SCE may be able to recover additional refunds from sellers of electricity during the crisis with whom settlements have not been reached.

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In November 2004, the CPUC issued a resolution authorizing SCE to establish an energy settlement memorandum account (ESMA) for the purpose of recording the foregoing settlement proceeds from energy providers and allocating them in accordance with a settlement agreement. The resolution provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA are allocated to recovery of SCE s litigation costs and expenses in the FERC refund proceedings described above and the 10% shareholder incentive. Remaining amounts for each settlement are to be refunded to ratepayers through the energy resource recovery account mechanism. During 2005, SCE recognized $23 million in shareholder incentives related to the FERC refunds described above.

Investigations Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability.

SCE has been conducting investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE s transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of approximately $10 million for 2003.

Following its internal investigation, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forgo an additional $5 million of the PBR rewards pending that are both attributable to the design organization s portion of the customer satisfaction rewards for the entire PBR period (1997 2003). In addition, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading. As a result of these findings, SCE accrued a $9 million charge in the caption Other nonoperating deductions on the income statement in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by disciplining employees and terminating the employment of employees, including several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 GRC.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE conducted an investigation into the accuracy of SCE s employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has received $20 million in employee safety incentives for 1997 through 2000 and, based on SCE s records, may be entitled to an additional $15 million for 2001 through 2003.

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On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE s performance under the PBR incentive mechanism for injury and illness reporting. SCE disclosed in the investigative findings to the CPUC that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism and return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in the caption Other nonoperating deductions on the income statement in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001 2003 time frames.

SCE has taken remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance, disciplining employees who committed wrongdoing and terminating an employee. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004.

CPUC Investigation

On June 15, 2006, the CPUC instituted a formal investigation to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, injury and illness reporting, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE.

In June 2006, the Consumer Protection and Safety Division (CPSD) of the CPUC issued its report regarding SCE s PBR program, recommending that the CPUC impose various refunds and penalties on SCE. Subsequently, in September 2006, the CPSD and other intervenors, such as the CPUC s Division of Ratepayer Advocates and The Utility Reform Network filed testimony on these matters recommending various refunds and penalties to be imposed upon SCE. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors. Based on SCE s proposal for refunds and the combined recommendations of the CPSD and other intervenors, the potential refunds and penalties could range from $32 million up to $396 million. Evidentiary hearings which will address the planning and meter reading components of customer satisfaction, safety, issues related to SCE s administration of the survey, and statutory fines associated with those matters are scheduled to take place in the fourth quarter of 2006. A schedule has not been set to address the other components of customer satisfaction, system reliability, and other issues. At this time, SCE cannot predict the outcome of these matters or reasonably estimate the potential amount of any additional refunds, disallowances, or penalties that may be required above the lower end of the range.

ISO Disputed Charges

On April 20, 2004, the FERC issued an order concerning a dispute between the ISO and the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California over the proper allocation and characterization of certain transmission service related charges. The order reversed an arbitrator s award that had affirmed the ISO s characterization in May 2000 of the charges as Intra-Zonal Congestion costs and allocation of those charges to scheduling coordinators in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from scheduling coordinators in the affected zone to the responsible participating transmission owner, SCE. The potential cost to SCE, net of amounts SCE expects to receive through the PX, SCE s scheduling coordinator at the time, is estimated to be approximately $20 million to $25 million, including interest. On April 20, 2005, the FERC stayed its April 20, 2004 order during the pendency of SCE s appeal filed with the Court of Appeals for the D.C. Circuit. On March 7, 2006, the Court of Appeals remanded the case back to the FERC at the FERC s request and with SCE s consent. A decision is expected by March 2007. The FERC may require SCE to pay these costs, but SCE does not believe this outcome is probable. If SCE is required to pay these costs, SCE may seek recovery in its reliability service rates.

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Leveraged Lease Investments

Edison Capital has a net leveraged lease investment of $58 million, before deferred taxes, in three aircraft leased to American Airlines. American Airlines has reported net losses since 2000. A default in the leveraged lease by American Airlines could result in a loss of some or all of Edison Capital s lease investment. At September 30, 2006, American Airlines was current in its lease payments to Edison Capital.

Edison Capital also has a net leveraged lease investment of $47 million, before deferred taxes, in a large natural gas-fired cogeneration plant leased to Midland Cogeneration Venture. During 2005, Midland Cogeneration Venture wrote down the book value of the power plant as a result of a substantial increase in long-term natural gas prices. A default of the lease could result in a loss of some or all of Edison Capital s lease investment. At September 30, 2006, Midland Cogeneration Venture was current in its payments under the lease.

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 (Midway-Sunset), which owns a 225-MW cogeneration facility near Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC because Midway-Sunset was a seller in the PX and ISO 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 PX and ISO markets, Midway-Sunset is potentially liable for refunds to purchasers in these markets. See discussion above in Federal Energy Regulatory Commission (FERC) Refund Proceedings .

The claims asserted against Midway-Sunset for refunds related to power sold into the PX and ISO 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 did not retain any proceeds from power sold into the PX and ISO 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 through those proceeds to the utilities. Since the proceeds were passed through 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 PX and ISO markets on their behalves.

During this period, amounts SCE received from Midway-Sunset were credited to SCE s customers against power purchase expenses through the ratemaking mechanism in place at that time. SCE believes that any net amounts reimbursed to Midway-Sunset would be substantially recoverable from its customers through current regulatory mechanisms. Edison International does not expect any refund payment made by Midway-Sunset, or any SCE reimbursement to Midway-Sunset, to have a material impact on earnings.

Midwest Independent Transmission System Operator (MISO) Revenue Sufficiency Guarantee Charges

On April 25, 2006, the FERC issued an order regarding the MISO s Revenue Sufficiency Guarantee charges (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

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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, the 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, the 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.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the U.S. District Court for the District of Columbia (District Court), against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organization (RICO) statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion.

In April 2004, the District Court dismissed SCE s motion for summary judgment and concluded that a related 2003 U.S. Supreme Court decision in a related lawsuit by the Navajo Nation against the U.S. Government did not preclude the Navajo Nation from pursuing its RICO and intentional tort claims.

Pursuant to a joint request of the parties, the D.C. District Court granted a stay of the action on October 5, 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. An initial, organizational session was held with the facilitator on October 14, 2004 and negotiations are on-going. On July 28, 2005, the District Court issued an order removing the case from its active calendar, subject to reinstatement at the request of any party.

SCE cannot predict the outcome of the 1999 Navajo Nation s complaint against SCE, the ultimate impact on the complaint of the Supreme Court s 2003 decision and the on-going litigation by the Navajo Nation against the Government in the related case, or the impact on the facilitated negotiations of SCE s recently announced decision to discontinue efforts to return Mohave to service.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $10.8 billion. SCE and other owners of San Onofre Nuclear Generating Station (San Onofre) and Palo Verde Nuclear Generating Station (Palo Verde) have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry s retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The current maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than $15 million per reactor may be charged in any one year for each incident. The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident will be adjusted for inflation on a 5-year schedule. The next inflation adjustment will occur on August 31, 2008. Based on its ownership interests, SCE could be

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required to pay a maximum of $199 million per nuclear incident. However, it would have to pay no more than $30 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $42 million per year. Insurance premiums are charged to operating expense.

Procurement of Renewable Resources

California law requires SCE to increase its procurement of renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. Recently enacted legislation, which will become effective on January 1, 2007, will amend existing law to accelerate the overall target from 2017 to 2010.

SCE previously entered into a contract with Calpine Energy Services, L.P. to purchase the output of certain existing geothermal facilities in northern California. Under previous CPUC decisions and reporting and compliance methodology, SCE was only able to count procurement pursuant to the Calpine contract towards its annual renewable target to the extent the output was certified as incremental by the California Energy Commission. On October 19, 2006, the CPUC issued a decision that revised the reporting and compliance methodology, and permitted SCE to count the entire output pursuant to its Calpine contract towards satisfaction of its annual renewable procurement target thus meeting its renewable procurement obligations for 2003, 2004, 2005 and 2006. The decision also implemented a cumulative deficit banking feature which would carry forward and accumulate annual deficits until the deficit has been satisfied at a later time through actual deliveries of eligible renewable energy.

Under the new methodology, SCE could have deficits in meeting its renewable procurement obligations for 2007, but will be in compliance for 2003 through 2006. SCE believes it may be able to demonstrate that it should not be penalized for the 2007 deficit through the CPUC s flexible compliance rules.

Under current CPUC decisions, potential penalties for SCE s failure to achieve its renewable procurement obligations for any year will be considered by the CPUC in the context of the CPUC s review of SCE s annual compliance filing. Under the CPUC s current rules, the maximum penalty for failing to achieve renewable procurement targets is $25 million per year. SCE cannot predict whether it will be assessed penalties.

Scheduling Coordinator Tariff Dispute

SCE serves as a scheduling coordinator for the Los Angeles DWP over the ISO-controlled grid. In late 2003, SCE began charging the DWP under a tariff subject to refund for FERC-authorized charges incurred by SCE on the DWP s behalf. The scheduling coordinator charges are billed to the DWP under a FERC tariff that remains subject to dispute. The DWP has paid the amounts billed under protest but requested that the FERC declare that SCE was obligated to serve as the DWP s scheduling coordinator without charge. The FERC accepted SCE s tariff for filing, but held that the rates charged to the DWP have not been shown to be just and reasonable and

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thus made them subject to refund and further review by the FERC. As a result, SCE could be required to refund all or part of the amounts collected from the DWP under the tariff. As of September 30, 2006, SCE has accrued a $36 million charge to earnings for the potential refunds. If the FERC ultimately rules that SCE may not collect the scheduling coordinator charges from the DWP and requires the amounts collected to be refunded to the DWP, SCE would attempt to recover the scheduling coordinator charges from all transmission grid customers through another regulatory mechanism. However, the availability of other recovery mechanisms is uncertain, and ultimate recovery of the scheduling coordinator charges cannot be assured.

Settlement Agreement with Duke Energy Trading and Marketing, LLC

On September 21, 2006, the CPUC approved a settlement agreement between SCE and Duke Energy Trading and Marketing, LLC (Duke) that resolved disputes arising from Duke s termination of certain bilateral power supply contracts in early 2001. Under the settlement, Duke made a $77 million principal and interest payment to SCE in October 2006, which will be refunded to ratepayers through the energy resource recovery account mechanism. The settlement also permitted $58 million in liabilities that SCE had previously recorded with respect to the Duke terminated contracts to be reversed, which resulted in an equivalent benefit recorded by SCE in the third quarter of 2006. The CPUC agreed that these liabilities should not be refunded to ratepayers. The recorded liabilities consisted of $40 million in cash collateral received from Duke in 2000 and $18 million in power purchase payments that SCE, in light of Duke s termination of the bilateral contracts, withheld for energy delivered by Duke in January 2001.

Spent Nuclear Fuel

Under federal law, the United States Department of Energy (DOE) is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to 0.1¢-per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE s failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. The case was stayed through April 7, 2006, when SCE and the DOE filed a Joint Status Report in which SCE sought to lift the stay and the government opposed lifting the stay. On June 5, 2006, the Court of Federal Claims lifted the stay on SCE s case and established a discovery schedule. A Joint Status Report is due on September 7, 2007, regarding further proceedings in this case presumably including establishing a trial date.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation where all of Unit 1 s spent fuel located at San Onofre is stored. There is now sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE is planning to begin moving Unit 2 and 3 spent fuel into the independent spent fuel storage installation by early 2007.

There are now sufficient dry casks and modules available to the independent spent fuel storage installation to meet plant requirements through 2008. SCE, as operating agent, plans to continually load casks on a schedule to maintain full core off-load capability for both units in order to meet the plant requirements after 2008 until 2022 (the end of the current Nuclear Regulatory Commission operating license).

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In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed a dry cask storage facility. Arizona Public Service, as operating agent, plans to continually load casks on a schedule to maintain full core off-load capability for all three units.

Note 4. Commitments

The following is an update to Edison International s commitments. See Note 8 of Notes to Consolidated Financial Statements included in Edison International s 2005 Annual Report for a detailed discussion.

Lease Commitments

Estimated remaining commitments (the majority of which are related to EME s long-term leases for the Powerton, Joliet and Homer City power plants) for noncancelable operating leases at September 30, 2006 are:

In millions		
		(Unaudited)
October through December 2006	$	124
2007		704
2008		675
2009		611
2010		566
Thereafter		3,056
Total	$	5,736

Other Commitments

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 (see further discussion related to the Wildorado project in Note 10, Acquisition and Disposition) and four other wind projects totaling 181 MW. Also included are expenditures for boiler head replacement, dust collection and mitigation system and various other smaller projects. These expenditures are planned to be financed by cash on hand or cash generated from operations or existing subsidiary credit agreements.

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.

Guarantees and Indemnities

Edison International s subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts included performance guarantees, guarantees of debt and indemnifications.

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Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Collins Station in Illinois, the Powerton and Joliet Stations 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 2004, Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor.

Indemnities Provided as Part of EME s Acquisition of the Illinois Plants

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

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation 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 EME s Acquisition of the Homer City Facilities

In connection with the acquisition of the Homer City facilities, EME Homer City Generation L.P. (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

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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.

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 agreements. 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.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE s previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. The generating station has not operated since early 2001. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

Other Edison International Indemnities

Edison International provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with

EDISON INTERNATIONAL

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. Edison International s obligations under these agreements may be limited in terms of time and/or amount, and in some instances Edison International may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. Edison International has not recorded a liability related to these indemnities.

Note 5. Business Segments

Edison International s reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (MEHC parent only and EME), and a financial services provider segment (Edison Capital).

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. As a result of this capital contribution, Edison International s nonutility power generation segment now includes the wind assets and biomass power project previously owned by Edison Capital. The resulting change in the structure of Edison International s internal organization and in accordance with an accounting standard related to operating segments, prior periods have been restated to conform to Edison International s new business segment definition.

Segment information was:

In millions	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(Unaudited)			
Operating Revenue:				
Electric utility	**$ 3,079**	$ 3,084	**$ 7,818**	$ 7,194
Nonutility power generation	**704**	680	**1,679**	1,619
Financial services	**18**	18	**56**	58
Corporate and other	**1**	1	**2**	7
Consolidated Edison International	**$ 3,802**	$ 3,783	**$ 9,555**	$ 8,878
Net Income (Loss):				
Electric utility(1)	**$ 263**	$ 280	**$ 618**	$ 572
Nonutility power generation(2)	**178**	182	**252**	239
Financial services	**24**	2	**45**	75
Corporate and other	**(7)**	(2)	**(22)**	(22)
Consolidated Edison International	**$ 458**	$ 462	**$ 893**	$ 864

(1) Net income available for common stock.

(2) Includes earnings (loss) from discontinued operations of $(2) million and $27 million, respectively, for the three months ended September 30, 2006 and 2005, and $75 million and $55 million, respectively, for the nine months ended September 30, 2006 and 2005.

Corporate and other includes amounts from nonutility subsidiaries not significant as a reportable segment.

Total segment assets as of September 30, 2006, were: electric utility, $26 billion; nonutility power generation, $7 billion; and, financial services, $3 billion.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 6. Liabilities and Lines of Credit

Long-Term Debt

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.

Reflecting the above refinancing transactions, long-term debt maturities and sinking fund requirements as of September 30, 2006 are:

In millions	(Unaudited)
October through December 2006	$ 106
2007	487
2008	878
2009	763
2010	314

Lines of Credit

At September 30, 2006, Edison International and its subsidiaries had $3.5 billion of borrowing capacity available under lines of credit totaling $3.7 billion. SCE had a $1.7 billion line of credit with $1.5 billion available. EME, including its subsidiary, Midwest Generation, had lines of credit of $959 million available under lines of credit totaling $1.0 billion. Edison International (parent) has a $1.0 billion line of credit available. These credit lines have various expiration dates, and when available, can be drawn down at negotiated or bank index rates.

These amounts have been updated primarily to reflect EME s financing activities completed during the second quarter of 2006. EME s new 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 of these ratio tests.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7. Preferred and Preference Stock of Utility Not Subject to Mandatory Redemption

In January 2006, SCE issued two million shares of 6.0% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of $197 million. The Series C preference stock may not be

redeemed prior to January 31, 2011. After January 31, 2011, SCE may, at its option, redeem the shares in whole or in part. The Series C preference stock has the same general characteristics as the Series A and B preference stock. See Note 4 of Notes to Consolidated Financial Statements included in Edison International s 2005 Annual Report for additional information on SCE s preference stock.

At September 30, 2006, accrued dividends related to SCE s preferred and preference stock not subject to mandatory redemption were $9 million.

Note 8. Mohave Shutdown

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Navajo Nation and Hopi Tribe (the Tribes). This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over a post-2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE s share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree.

On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE s decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE s customers. Two of the other Mohave co-owners, Nevada Power Company and the Los Angeles Department of Water & Power, made similar announcements, while the fourth co-owner, Salt River Project Agricultural Improvement and Power District (SRP), has announced that it is pursuing the possibility of putting together a successor owner group, which would include SRP, to pursue continued coal operations. All of the co-owners are evaluating the range of options for disposition of the plant, which conceivably could include, among other potential options, sale of the plant as is to a power plant operator, decommissioning and sale of the property to a developer, and decommissioning and apportionment of the land among the owners. At this time, SCE continues to work with the water and coal suppliers to the plant to determine if more clarity around the provision of such services can be provided to any potential acquirer.

Following the suspension of Mohave operations at the end of 2005, the plant s workforce will be reduced from over 300 employees to approximately 65 employees by the end of 2006. Approximately $7 million in termination costs were recorded in the second quarter and an additional $9 million were recorded in the third quarter (both SCE s share). Both amounts were deferred in a balancing account authorized in the 2006 GRC decision. SCE expects to recover amounts in this balancing account in future rate-making proceedings.

As of September 30, 2006, SCE had a Mohave net regulatory asset of approximately $89 million representing unamortized capital costs and inventory, partially offset by revenue collected for future removal costs. Based on the 2006 GRC decision, SCE is allowed to continue to earn its authorized rate of return on the Mohave investment and receive rate recovery for amortization, costs of removal, and operating and maintenance expenses, subject to balancing account treatment, during the three-year 2006 rate case cycle. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave, pursuant to

EDISON INTERNATIONAL

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

California law requiring such notice to the CPUC whenever a plant has been out of service for nine consecutive months. SCE also reported to the CPUC on Mohave s status numerous times previously. Pursuant to the statute the CPUC may institute an investigation to determine whether to reduce SCE s rates. At this time, SCE does not anticipate that the CPUC will order a rate reduction. In the past, the CPUC has allowed full recovery of investment for similarly situated plants. However, in a December 2004 decision, the CPUC noted that SCE would not be allowed to recover any unamortized plant balances if SCE could not demonstrate that it took all steps to preserve the Mohave-open alternative. SCE believes that it will be able to demonstrate that SCE did everything reasonably possible to return Mohave to service, which it further believes would permit its unamortized costs to be recovered in future rates. However, SCE cannot predict the outcome of any future CPUC action.

Note 9. Discontinued Operations

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project, pursuant to a purchase agreement dated December 15, 2004, to a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as IPM, for approximately $20 million. The sale of this investment had no significant effect on net income in the first quarter of 2005.

On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) project to Corporacion IMPSA S.A., pursuant to a purchase agreement dated November 5, 2004. 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.

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 its 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 zero 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.

For all periods presented, the results of EME s projects discussed above have been accounted for as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets.

For the three months ended September 30, 2006, and 2005, there was no revenue from discontinued operations and pre-tax loss was $(2) million for each period. For the nine months ended September 30, 2006, and 2005, there was no revenue from discontinued operations and pre-tax income was $117 million and $20 million, respectively. For the nine months ended September 30, 2005, there was a $9 million gain on sale before taxes.

There were no assets or liabilities of discontinued operations at September 30, 2006. At December 31, 2005, the assets and liabilities of discontinued operations were segregated on the consolidated balance sheet and consisted of current assets of $2 million, other long-term assets of $9 million and long-term liabilities of $14 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 10. Acquisition and Disposition

Acquisition

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-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 in 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 nonutility property in Edison International s consolidated balance sheet.

Disposition

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.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

INTRODUCTION

This Management s Discussion and Analysis of Financial Condition and Results of Operation (MD&A) for the three- and nine-month periods ended September 30, 2006 discusses material changes in the financial condition, results of operations and other developments of Edison International since December 31, 2005, and as compared to the three- and nine-month periods ended September 30, 2005. This discussion presumes that the reader has read or has access to Edison International s MD&A for the calendar year 2005 (the year-ended 2005 MD&A), which was included in Edison International s 2005 annual report to shareholders and incorporated by reference into Edison International s Annual Report on Form 10-K for the year ended December 31, 2005, filed with the Securities and Exchange Commission.

This MD&A contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements reflect Edison International s current expectations and projections about future events based on Edison International 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 Edison International that is incorporated in this report, or that refers to or incorporates this report, may also contain forward-looking statements. In this report and elsewhere, the words expects, believes, anticipates, estimates, projects, inte plans, probable, may, will, could, would, should, and variations of such words and similar expressions, or discussions of strategy or of 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 Edison International or its subsidiaries, include, but are not limited to:

- the ability of Edison International to meet its financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay dividends;
- the ability of Southern California Edison Company (SCE) to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the California Public Utilities Commission (CPUC) and other regulatory authorities and delays in regulatory actions;
- market risks affecting SCE s energy procurement activities;
- access to capital markets and the cost of capital;
- changes in interest rates, rates of inflation and foreign exchange rates;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and environmental regulations that could require additional expenditures or otherwise affect the cost and manner of doing business;
- risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage, equipment failure, availability, heat rate, output, and availability and cost of spare parts and repairs;
- the availability of labor, equipment and materials;

the ability to obtain sufficient insurance, including insurance relating to SCE s nuclear facilities;

effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;

the outcome of disputes with the Internal Revenue Service (IRS) and other tax authorities regarding tax positions taken by Edison International;

supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which Edison Mission Group Inc. s (EMG) generating units have access;

the cost and availability of coal, natural gas, fuel oil, nuclear fuel, and associated transportation;

the cost and availability of emission credits or allowances for emission credits;

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

the ability to provide sufficient collateral in support of hedging activities and purchased power and fuel;

the risk of counter-party default in hedging transactions or fuel contracts;

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;

the difficulty of predicting wholesale prices, transmission congestion, energy demand and other activities in the complex and volatile markets in which EMG and its subsidiaries participate;

general political, economic and business conditions;

weather conditions, natural disasters and other unforeseen events; and

changes in the fair value of investments and other assets.

Additional information about risks and uncertainties, including more detail about the factors described above, are discussed throughout this MD&A and in the Risk Factors section included in Part I, Item 1A of Edison International s Annual Report on Form 10-K for the year ended December 31, 2005. Readers are urged to read this entire report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect Edison International s business. Forward-looking statements speak only as of the date they are made and Edison International is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by Edison International with the Securities and Exchange Commission.

Edison International is engaged in the business of holding, for investment, the common stock of its subsidiaries. Edison International s principal operating subsidiaries are SCE, Edison Mission Energy (EME) and Edison Capital. EMG is the holding company for its principal wholly owned subsidiaries, Mission Energy Holding Company (MEHC) and Edison Capital. MEHC is the holding company for its wholly owned subsidiary, EME. Beginning in 2006, MEHC and Edison Capital are presented on a consolidated basis as EMG. This change has been made to reflect the integration of management and personnel at MEHC and Edison Capital.

In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, EMG, MEHC, EME or Edison Capital mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company and

MEHC (parent) mean Edison International or MEHC on a stand-alone basis, not consolidated with its subsidiaries.

This MD&A is presented in nine major sections. The MD&A begins with a discussion of current developments. Following is a company-by-company discussion of SCE, EMG, and Edison International (parent) which includes

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discussions of liquidity, market risk exposures, and other matters (as relevant to each principal business segment). The remaining sections discuss Edison International on a consolidated basis. The consolidated sections should be read in conjunction with the discussion of each company s section.

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CURRENT DEVELOPMENTS

The following section provides a summary of current developments related to Edison International s principal business segments. This section is intended to be a summary of those current developments that management believes are of most importance since year-end December 31, 2005. This section is not intended to be an all-inclusive list of all current developments related to each principal business segment. Further details of each current development discussed below can be found in the specific principal business segment s section of this MD&A, along with discussions of liquidity, market risk exposures, and other matters as relevant to each principal business segment.

SCE: CURRENT DEVELOPMENTS

2006 General Rate Case Proceeding

On May 11, 2006, the CPUC issued its final decision authorizing an increase of $274 million over SCE s 2005 base rate revenue, retroactive to January 12, 2006. The CPUC also authorized increases of $74 million in 2007 and $104 million in 2008. See SCE: Regulatory Matters Current Regulatory Developments 2006 General Rate Case Proceeding for further discussion.

2007 Cost of Capital Proceeding

On August 24, 2006, the CPUC issued a final decision granting SCE s request to waive the requirement that SCE file a 2007 cost of capital application and instead file its next application in 2007 for year 2008. As a result, SCE s authorized capital structure, return on common equity of 11.60% and overall rate of return on capital of 8.77%, will not change for 2007. See SCE: Regulatory Matters Current Regulatory Developments 2007 Cost of Capital Proceeding for further discussion.

2006 FERC Rate Case

On July 6, 2006, the Federal Energy Regulatory Commission (FERC) approved a settlement that set a revenue requirement of $312 million, which increases SCE s revenue requirement by $26 million over 2006 base transmission rates (which were authorized in 2003). See SCE: Regulatory Matters Current Regulatory Developments 2006 FERC Rate Case for further discussion.

Mohave Generating Station and Related Proceedings

On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE s decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE s customers. See SCE: Regulatory Matters Current Regulatory Developments Mohave Generating Station and Related Proceedings for further discussion.

Peaker Plant Generation Projects

On August 15, 2006, the CPUC issued a ruling addressing electric reliability needs in Southern California for the summer of 2007 and directing, among other things, that SCE pursue new utility-owned peaker generation (which would be available on notice during peak demand periods) that would be online in time for the summer of 2007. SCE is currently pursuing the construction and siting of up to five combustion turbine peaker plants, each with a capacity of approximately 45 MW. SCE expects to spend a total of approximately $250 million on these projects. See SCE: Regulatory Matters Current Regulatory Developments Peaker Plant Generation Projects for further discussion.

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EMG: CURRENT DEVELOPMENTS

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, Edison Mission Marketing & Trading Inc. (EMMT) entered into two load requirements services contracts. Under the terms of these agreements, Midwest Generation LLC (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 EMG: Market Risk Exposures MEHC s 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. 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 state implementation plant (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 Other Developments Environmental Matters for further discussion of environmental developments.

MEHC: 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.

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.

MEHC: 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.

MEHC: 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

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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.

MEHC: Homer City Transformer Failure

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.

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SOUTHERN CALIFORNIA EDISON COMPANY

SCE: LIQUIDITY

Overview

As of September 30, 2006, SCE had cash and equivalents of $158 million ($108 million of which was held by SCE s consolidated Variable Interest Entities). As of September 30, 2006, long-term debt, including current maturities of long-term debt, was $5.2 billion. In December 2005, SCE replaced its $1.25 billion credit facility with a $1.7 billion five-year senior secured credit facility. The security pledged (first and refunding mortgage bonds) for the new facility can be removed at SCE s discretion. If SCE chooses to remove the security, the credit facility s pricing will change to an unsecured basis per the terms of the credit facility agreement. As of September 30, 2006, SCE s credit facility supported $189 million in letters of credit, leaving $1.5 billion available under the credit facility.

SCE s estimated cash outflows during the twelve-month period following September 30, 2006 consist of:

Debt maturities of approximately $247 million of rate reduction notes that have a separate nonbypassable recovery mechanism approved by state legislation and CPUC decisions;

Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct generation assets (see SCE: Regulatory Matters Current Regulatory Developments Peaker Plant Generation Projects);

Dividend payments to SCE s parent company. SCE made dividend payments to Edison International of $71 million on January 16, 2006, and $60 million on each of April 28, 2006, July 24, 2006 and October 26, 2006;

Fuel and procurement-related costs (see SCE: Regulatory Matters Current Regulatory Developments Energy Resource Recovery Account Proceedings); and

General operating expenses.

SCE expects to meet its continuing obligations, including cash outflows for operating expenses, including power-procurement, through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary. Projected capital expenditures are expected to be financed through operating cash flows and the issuance of short-term and long-term debt and preferred equity.

SCE s liquidity may be affected by, among other things, matters described in SCE: Regulatory Matters.

Credit Ratings

At September 30, 2006, SCE s credit rating on long-term senior secured debt from Standard & Poor s Rating Services and Moody s Investors Service were BBB+ and A3, respectively. On October 16, 2006, Moody s Investors Service raised SCE s senior secured credit rating from A3 to A2. At September 30, 2006, SCE s short-term (commercial paper) credit ratings from Standard & Poor s and Moody s were A-2 and P-2, respectively.

Dividend Restrictions and Debt Covenants

The CPUC regulates SCE s capital structure and limits the dividends it may pay Edison International (see Edison International (Parent): Liquidity for further discussion). In SCE s most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At September 30, 2006, SCE s 13-month weighted-average common equity component of total

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capitalization was 50%. At September 30, 2006, SCE had the capacity to pay $164 million in additional dividends based on the 13-month weighted-average method. Based on recorded September 30, 2006 balances, SCE s common equity to total capitalization ratio, for rate-making purposes, was 50%. SCE had the capacity to pay $260 million of additional dividends to Edison International based on September 30, 2006 recorded balances.

SCE has a debt covenant in its credit facility that requires a debt to total capitalization ratio of less than or equal to 0.65 to 1 to be met. At September 30, 2006, SCE s debt to total capitalization ratio was 0.44 to 1.

Margin and Collateral Deposits

SCE has entered into certain margining agreements for power and gas trading activities in support of its procurement plan as approved by the CPUC. SCE s margin deposit requirements under these agreements can vary depending upon the level of unsecured credit extended by counterparties and brokers and changes in market prices relative to contractual commitments, and other factors. At September 30, 2006, SCE had a net deposit of $148 million (consisting of $36 million in cash and reflected in Margin and collateral deposits on the balance sheet and $112 million in letters of credit) with a broker. In addition, SCE has deposited $107 million (consisting of $30 million in cash and reflected in Margin and collateral deposits on the balance sheet and $77 million in letters of credit) with other brokers and counterparties. Cash deposits with brokers and counterparties earn interest at various rates.

Margin and collateral deposits in support of power contracts and trading activities fluctuate with changes in market prices. Future margin and collateral requirements may be higher or lower than the margin collateral requirements as of September 30, 2006, based on future market prices and volumes of contractual and trading activity.

SCE: REGULATORY MATTERS

Current Regulatory Developments

This section of the MD&A describes significant regulatory issues that may impact SCE s financial condition or results of operation.

Impact of Regulatory Matters on Customer Rates

SCE is concerned about high customer rates, which were a contributing factor that led to the deregulation of the electric services industry during the mid-1990s. On January 1, 2006, SCE implemented a rate change that resulted in a system average rate of 13.7¢-per-kilowatt-hour (kWh). Of the 1.1¢ rate increase, 1¢ was due to the implementation of the California Department of Water Resources (CDWR) 2006 revenue requirement approved by the California Public Utilities Commission (CPUC) on December 1, 2005.

SCE implemented another rate change on February 4, 2006. As a result, SCE s system average rate increased to 14.3¢-per-kWh. The rate increase was due to a 1.2¢ increase resulting from the implementation of SCE s 2006 Energy Resource Recovery Account (ERRA) forecast discussed below, partially offset by a decrease of 0.7¢ due to spreading of the revenue requirement over a larger customer base resulting from forecast sales growth. In addition, the rate change includes authorized increases in funding for energy efficiency programs.

As of June 4, 2006, SCE s system average rate was 14.5¢-per-kWh after increases associated with demand response program funding and FERC transmission-related rates. Except for residential rates, on August 1, 2006, SCE implemented in rates the 2006 General Rate Case (GRC) decision and modified the FERC-jurisdictional base transmission-related rates for the revised revenue requirement approved in the settlement discussed below. To mitigate the impact of further rate increases on residential customers during a period of record heat conditions in Southern California, on July 26, 2006, the CPUC granted SCE s request to defer the residential rate increase to

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November 1, 2006. On July 27, 2006, SCE filed an advice letter with the CPUC seeking approval of the mechanism in which SCE will collect the authorized revenue earned during this deferral period over a twelve month period beginning January 1, 2007. On October 19, 2006, the CPUC approved SCE s request to further defer the residential increase to January 1, 2007 and approved the recovery mechanism. Under regulatory accounting, SCE is entitled to recognize revenue based on amounts authorized. As a result, the revenue associated with the residential rate increase is recognized as earned; however, collection is being deferred until January 1, 2007. On October 1, 2006, SCE implemented a rate increase modifying the FERC-jurisdictional rates to recover costs approved by the FERC associated with the ancillary services and losses SCE has incurred in administering wholesale transmission contracts after implementation of the restructured California electric industry. SCE s current system average rate, as of October 1, 2006, is approximately 14.8¢-per-kWh.

2006 General Rate Case Proceeding

On December 21, 2004, SCE filed its application for a 2006 GRC and subsequently revised its requested 2006 base rate revenue requirement to $3.96 billion, an increase of $465 million over SCE s 2005 base rate revenue. When a one-time credit of $140 million from an existing balancing account overcollection was applied, SCE s requested increase was $325 million. SCE also proposed revised base rate revenue increases of $108 million for 2007 and $113 million for 2008.

On May 11, 2006, the CPUC issued its final decision authorizing an increase of $274 million over SCE s 2005 base rate revenue, retroactive to January 12, 2006. When the one-time credit of $140 million from an existing balancing account overcollection was applied, SCE s authorized increase was $134 million. The CPUC also authorized increases of $74 million in 2007 and $104 million in 2008. The decision substantially approved SCE s request to continue its capital investment program for infrastructure replacement and expansion, with authorized revenue in excess of costs for this program subject to refund. In addition, the decision provided for balancing accounts for pensions, postretirement medical benefits and certain incentive compensation expense.

During the second quarter of 2006, SCE implemented the 2006 GRC decision and resolved an outstanding regulatory issue which resulted in a pre-tax benefit of approximately $175 million. The implementation of the 2006 GRC decision retroactive to January 12, 2006 mainly resulted in revenue of $50 million related to the revenue requirement for the period January 12, 2006 through May 31, 2006, partially offset by the implementation of the new depreciation rates resulting in increased depreciation expense of approximately $25 million for the period January 12, 2006 through May 31, 2006. In addition, there was a favorable resolution of a one-time issue related to a portion of revenue collected during the 2001 2003 period for state income taxes. SCE was able to determine through regulatory proceedings, including the 2006 GRC decision, that the level of revenue collected during that period was appropriate, and as a result recorded a pre-tax gain of $135 million (reflected in the caption Provisions for regulatory adjustments clauses net on the income statement). See SCE: Regulatory Matters Impact of Regulatory Matters on Customer Rates for further discussion.

2007 Cost of Capital Proceeding

On March 27, 2006, SCE initiated proceedings requesting the CPUC to waive the requirement that SCE file a 2007 cost of capital application and instead file its next application in 2007 for year 2008. On August 24, 2006, the CPUC issued a final decision granting SCE s waiver application and, as a result, SCE s authorized capital structure, return on common equity of 11.60% and overall rate of return on capital of 8.77%, will not change for 2007.

2006 FERC Rate Case

SCE s electric transmission revenue and wholesale and retail transmission rates are subject to authorization by the FERC. On November 10, 2005, SCE filed proposed revisions to the 2006 base transmission rates, which would increase SCE s revenue requirement by $65 million, or 23%, over 2006 base transmission rates (which were authorized in 2003) and requested an effective date of January 10, 2006. On May 30, 2006, the FERC authorized an effective date for the new rates of June 4, 2006 (SCE s request for rehearing on the effective date issue was subsequently denied). On July 6, 2006, the FERC approved a settlement that set a revenue requirement of $312 million, which increases SCE s revenue requirement by $26 million over 2006 base transmission rates. See SCE: Regulatory Matters Impact of Regulatory Matters on Customer Rates.

Energy Resource Recovery Account Proceedings

As discussed under the heading Regulatory Matters Current Regulatory Developments Energy Resource Recovery Account Proceedings in the year-ended 2005 MD&A, the ERRA is the balancing account mechanism to track and recover SCE s fuel and procurement-related costs. If the ERRA balancing account incurs an overcollection or undercollection in excess of 4% of SCE s prior year s generation revenue, the CPUC has established a trigger mechanism, whereby SCE must file an application in which it can request an emergency rate adjustment if the ERRA overcollection or undercollection exceeds 5% of SCE s prior year s generation revenue.

At the end of July 2006, the ERRA was overcollected by $231 million, which was 5.79% of SCE s prior year s generation revenue. As of September 30, 2006, the ERRA was overcollected by $449 million, which was 11.2% of SCE s prior year s generation revenue. In addition, SCE forecasts that the overcollection will remain above the 5% threshold for the remainder of 2006.

As a result of the July 2006 overcollection, on September 1, 2006, SCE filed an ERRA trigger application proposing that no further rate action be taken and that SCE be allowed to maintain its currently authorized ERRA rates for the remainder of 2006 and to consolidate any ERRA rate change with other rate changes to become effective on January 1, 2007. SCE received no opposition to this proposal and anticipates a favorable CPUC decision by the end of 2006.

Resource Adequacy Requirements

Under the CPUC s resource adequacy framework, all load-serving entities in California have an obligation to procure sufficient resources to meet their expected customers needs on a system-wide basis with a 15 17% reserve level. In addition, on June 6, 2006, the CPUC adopted local resource adequacy requirements.

Effective February 16, 2006, SCE was required to demonstrate that it had procured sufficient resources to meet 90% of its June September 2006 system resource adequacy requirement. SCE believes that it has met this requirement. Beginning in May 2006, SCE is required to demonstrate every month that it has met 100% of its system resource adequacy requirement one month in advance of expected need. The system resource adequacy requirements provide for penalties of 150% of the cost of new monthly capacity for failing to meet the system resource adequacy requirements in 2006, and a 300% penalty in 2007 and beyond. SCE believes it has procured sufficient resources to meet its expected system resource adequacy requirements for 2006.

Under the local resource adequacy requirements, SCE must demonstrate that it has procured 100% of its requirement within defined local areas. The local resource adequacy requirements provide for penalties of 100% of the cost of new monthly capacity for failing to meet the local resource adequacy requirements. During the third quarter of 2006, the CPUC established the amount of local capacity necessary for SCE to meet its local resource adequacy requirements. SCE made a showing of compliance with its local resource adequacy requirements for 2007 on November 2, 2006. SCE believes it has procured sufficient resources to meet its expected local resource adequacy requirements for 2007.

Peaker Plant Generation Projects

On August 15, 2006, the CPUC issued a ruling addressing electric reliability needs in Southern California for the summer of 2007 and directing, among other things, that SCE pursue new utility-owned peaker generation (which would be available on notice during peak demand periods) that would be online in time for the summer of 2007. SCE is currently pursuing the construction and siting of up to five combustion turbine peaker plants, each with a capacity of approximately 45 MW. SCE expects to spend a total of approximately $250 million on these projects. SCE submitted an advice letter to the CPUC seeking recovery of these costs. A decision on this filing is expected in November 2006. After the peaker plants are in operation, SCE will be required to submit a review application to determine the reasonableness of the costs. If the CPUC finds any of the costs to be unreasonable, appropriate rate adjustments will be made.

Procurement of Renewable Resources

California law requires SCE to increase its procurement of renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. Recently enacted legislation, which will become effective on January 1, 2007, will amend existing law to accelerate the overall target from 2017 to 2010.

SCE previously entered into a contract with Calpine Energy Services, L.P. to purchase the output of certain existing geothermal facilities in northern California. Under previous CPUC decisions and reporting and compliance methodology, SCE was only able to count procurement pursuant to the Calpine contract towards its annual renewable target to the extent the output was certified as incremental by the California Energy Commission (CEC). On October 19, 2006, the CPUC issued a decision that revised the reporting and compliance methodology, and permitted SCE to count the entire output pursuant to its Calpine contract towards satisfaction of its annual renewable procurement target thus meeting its renewable procurement obligations for 2003, 2004, 2005 and 2006. The decision also implemented a cumulative deficit banking feature which would carry forward and accumulate annual deficits until the deficit has been satisfied at a later time through actual deliveries of eligible renewable energy.

Under the new methodology, SCE could have deficits in meeting its renewable procurement obligations for 2007, but will be in compliance for 2003 through 2006. SCE believes it may be able to demonstrate that it should not be penalized for the 2007 deficit through the CPUC s flexible compliance rules.

Under current CPUC decisions, potential penalties for SCE s failure to achieve its renewable procurement obligations for any year will be considered by the CPUC in the context of the CPUC s review of SCE s annual compliance filing. Under the CPUC s current rules, the maximum penalty for failing to achieve renewable procurement targets is $25 million per year. SCE cannot predict whether it will be assessed penalties.

Request for Offers from Renewable Resources

SCE is engaged in several initiatives to meet the requirement that it procure renewable resources, including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives. On July 14, 2006, SCE requested proposals for power purchase contracts from renewable energy resources, with bids received in September 2006. SCE is currently reviewing these bids in order to conduct further negotiations with selected bidders in an attempt to enter into final contracts. The contract lengths will be 10, 15 or 20 years.

Mohave Generating Station and Related Proceedings

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Navajo Nation and Hopi Tribe (the Tribes). This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over a post-2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE s share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree.

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On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE s decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE s customers. Two of the other Mohave co-owners, Nevada Power Company and the Los Angeles Department of Water & Power, made similar announcements, while the fourth co-owner, Salt River Project Agricultural Improvement and Power District (SRP), has announced that it is pursuing the possibility of putting together a successor owner group, which would include SRP, to pursue continued coal operations. All of the co-owners are evaluating the range of options for disposition of the plant, which conceivably could include, among other potential options, sale of the plant as is to a power plant operator, decommissioning and sale of the property to a developer, and decommissioning and apportionment of the land among the owners. At this time, SCE continues to work with the water and coal suppliers to the plant to determine if more clarity around the provision of such services can be provided to any potential acquirer.

Following the suspension of Mohave operations at the end of 2005, the plant s workforce will be reduced from over 300 employees to approximately 65 employees by the end of 2006. Approximately $7 million in termination costs were recorded in the second quarter and an additional $9 million were recorded in the third quarter (both SCE s share). Both amounts were deferred in a balancing account authorized in the 2006 GRC decision. SCE expects to recover amounts in this balancing account in future rate-making proceedings.

As of September 30, 2006, SCE had a Mohave net regulatory asset of approximately $89 million representing unamortized capital costs and inventory, partially offset by revenue collected for future removal costs. Based on the 2006 GRC decision, SCE is allowed to continue to earn its authorized rate of return on the Mohave investment and receive rate recovery for amortization, costs of removal, and operating and maintenance expenses, subject to balancing account treatment, during the three-year 2006 rate case cycle. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave, pursuant to California law requiring such notice to the CPUC whenever a plant has been out of service for nine consecutive months. SCE also reported to the CPUC on Mohave s status numerous times previously. Pursuant to the statute the CPUC may institute an investigation to determine whether to reduce SCE s rates. At this time, SCE does not anticipate that the CPUC will order a rate reduction. In the past, the CPUC has allowed full recovery of investment for similarly situated plants. However, in a December 2004 decision, the CPUC noted that SCE would not be allowed to recover any unamortized plant balances if SCE could not demonstrate that it took all steps to preserve the Mohave-open alternative. SCE believes that it will be able to demonstrate that SCE did everything reasonably possible to return Mohave to service, which it further believes would permit its unamortized costs to be recovered in future rates. However, SCE cannot predict the outcome of any future CPUC action.

San Onofre Nuclear Generating Station Steam Generators

As discussed under the heading Regulatory Matters Current Regulatory Developments San Onofre Nuclear Generating Station Steam Generators in the year-ended 2005 MD&A, on December 15, 2005, the CPUC issued a final decision on SCE s application for replacement of SCE s San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 steam generators. On June 15, 2006, the CPUC granted a limited rehearing of the decision in response to an Application for Rehearing filed by The Utility Reform Network and California Earth Corps challenging the cost effectiveness of the steam generator replacement project. SCE expects the CPUC to issue its decision affirming the cost effectiveness of the steam generator replacement project during the fourth quarter of 2006.

The city of Anaheim opted out of the project and agreed to transfer its 3.16% share of San Onofre to SCE. In March 2006, SCE filed applications to the Nuclear Regulatory Commission (NRC) and the FERC requesting authority to transfer Anaheim s share to SCE. Also, in March 2006, SCE filed an application with the CPUC requesting rate recovery for Anaheim s share of San Onofre operating and decommissioning costs. SCE received authority to acquire Anaheim s share from the FERC in April 2006 and from the NRC in September 2006. SCE expects to receive authority to recover Anaheim s share of San Onofre operating and decommissioning costs from the CPUC during the fourth quarter of 2006. The transfer of Anaheim s share is expected to occur in late 2006.

On April 14, 2006, San Diego Gas & Electric Company (SDG&E) applied to the CPUC to participate in the steam generator replacement and retain its 20% share of San Onofre contingent upon CPUC adoption of its application subject to certain conditions including authorization of an operating and maintenance expense balancing account and an 11.6% return on equity for SDG&E s San Onofre capital investment. If the CPUC s decision is not acceptable to SDG&E, it may file an application with the CPUC to opt out of steam generator replacement and have its ownership share of San Onofre reduced.

Palo Verde Nuclear Generating Station Steam Generators

SCE owns a 15.8% interest in the Palo Verde Nuclear Generating Station (Palo Verde). During 2003, the Palo Verde Unit 2 steam generators were replaced. During 2005, the Palo Verde Unit 1 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture and installation of steam generators in Unit 3. SCE expects that replacement steam generators will be installed in Unit 3 by the end of 2007. SCE s share of the costs of manufacturing and installing all of the replacement steam generators at Palo Verde is estimated to be approximately $115 million. The CPUC approved the replacement costs for Unit 2 in the 2003 GRC. The final decision in the 2006 GRC proceeding authorized SCE to recover the replacement costs for Units 1 and 3.

FERC Refund Proceedings

As discussed under the heading SCE: Regulatory Matters Current Regulatory Developments FERC Refund Proceedings in the year-ended 2005 MD&A, SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets during the energy crisis in California in 2000 2001 or who benefited from the manipulation by receiving inflated market prices. SCE is required to refund to customers 90% of any refunds actually realized by SCE, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

During the course of the refund proceedings, the FERC ruled that governmental power sellers, like private generators and marketers that sold into the California market, should refund the excessive prices they received during the crisis period. However, on September 21, 2005, the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) ruled that the FERC does not have authority directly to enforce its refund orders against governmental power sellers. The Court however, clarified that its decision does not preclude SCE or other parties from pursuing civil claims against the governmental power sellers. On March 16, 2006, SCE, Pacific Gas and Electric Company (PG&E) and the California Electricity Oversight Board jointly filed suit in federal court against several governmental power sellers, seeking refunds based on the reduced prices set by the FERC for transactions during the crisis period. SCE cannot predict whether it may be able to recover any additional refunds from governmental power sellers as a result of this suit.

In November 2005, SCE and other parties entered into a settlement agreement with Enron Corporation and a number of its affiliates, most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In April 2006, SCE received an additional distribution on its allowed bankruptcy claim of approximately $29 million, and 196,245 shares of common stock of Portland General Electric Company with an aggregate value of approximately $5 million. In October 2006, SCE received another distribution on its allowed bankruptcy claim of approximately $20 million and 17,040 shares of Portland General Electric Company stock, with an aggregate value of less than $1 million. Additional distributions are expected but SCE cannot currently predict the amount or timing of such distributions.

In December 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E, several governmental entities and certain other parties, and Reliant Energy, Inc. and a number of its affiliates. In March 2006, SCE received an additional $61 million as part of the settlement.

On August 2, 2006, the Ninth Circuit issued an opinion regarding the scope of refunds issued by the FERC. The Ninth Circuit widened the time period during which refunds could be issued to include the summer of 2000 for tariff violations and broadened the categories of transactions that could be subject to refund. As a result of this decision, SCE may be able to recover additional refunds from sellers of electricity during the crisis with whom settlements have not been reached.

Holding Company Order Instituting Rulemaking

On October 27, 2005, the CPUC issued an Order Instituting Rulemaking (OIR) to allow the CPUC to re-examine the relationships of the major California energy utilities with their parent holding companies and nonregulated affiliates. On June 29, 2006, the CPUC issued an opinion amending the October 2005 order. The opinion elaborates the CPUC s reasons for opening the OIR and invites comment on a number of perceived problems and potential solutions relating to the relationships between utilities, holding companies and nonregulated energy affiliates. The opinion also included the CPUC staff proposals for revisions to the affiliate transaction rules and the utility executive compensation reporting rules. Finally, the opinion expanded the process for the OIR to include participation of interested third parties through filed comments, a workshop, and oral argument. Respondent utilities and holding companies and other interested parties have completed briefings and a workshop to discuss the issues raised in the amended order.

On October 10, 2006, the CPUC issued a proposed decision that would amend the affiliate transaction rules and the executive compensation reporting rules. SCE and Edison International oppose some of the rule changes because they significantly alter relationships between the public utilities and their holding companies and nonregulated affiliates without clear evidentiary support; reduce operational efficiencies and increase regulatory compliance costs; and unnecessarily interfere with corporate governance and oversight. The CPUC has stated that it intends to conclude this rulemaking by the end of 2006. Edison International cannot predict the outcome of this proceeding.

Investigations Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability.

SCE has been conducting investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE s transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of approximately $10 million for 2003.

Following its internal investigation, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forgo an additional $5 million of the PBR rewards pending that are both attributable to

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the design organization s portion of the customer satisfaction rewards for the entire PBR period (1997 2003). In addition, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading. As a result of these findings, SCE accrued a $9 million charge in the caption Other nonoperating deductions on the income statement in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by disciplining employees and terminating the employment of employees, including several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 GRC.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE conducted an investigation into the accuracy of SCE s employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has received $20 million in employee safety incentives for 1997 through 2000 and, based on SCE s records, may be entitled to an additional $15 million for 2001 through 2003.

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE s performance under the PBR incentive mechanism for injury and illness reporting. SCE disclosed in the investigative findings to the CPUC that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism and return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in the caption Other nonoperating deductions on the income statement in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001 2003 time frames.

SCE has taken remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance, disciplining employees who committed wrongdoing and terminating an employee. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE conducted an investigation into the third PBR metric, system reliability. On February 28, 2005, SCE provided its final investigatory report to the CPUC concluding that the reliability reporting system is working as intended.

CPUC Investigation

On June 15, 2006, the CPUC instituted a formal investigation to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, injury and illness reporting, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE.

In June 2006, the Consumer Protection and Safety Division (CPSD) of the CPUC issued its report regarding SCE s PBR program, recommending that the CPUC impose various refunds and penalties on SCE. Subsequently, in September 2006, the CPSD and other intervenors, such as the CPUC s Division of Ratepayer Advocates and

The Utility Reform Network filed testimony on these matters recommending various refunds and penalties to be imposed upon SCE. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors. Based on SCE s proposal for refunds and the combined recommendations of the CPSD and other intervenors, the potential refunds and penalties could range from $32 million up to $396 million. Evidentiary hearings which will address the planning and meter reading components of customer satisfaction, safety, issues related to SCE s administration of the survey, and statutory fines associated with those matters are scheduled to take place in the fourth quarter of 2006. A schedule has not been set to address the other components of customer satisfaction, system reliability, and other issues. At this time, SCE cannot predict the outcome of these matters or reasonably estimate the potential amount of any additional refunds, disallowances, or penalties that may be required above the lower end of the range.

Settlement Agreement with Duke Energy Trading and Marketing, LLC

On September 21, 2006, the CPUC approved a settlement agreement between SCE and Duke Energy Trading and Marketing, LLC (Duke) that resolved disputes arising from Duke s termination of certain bilateral power supply contracts in early 2001. Under the settlement, Duke made a $77 million principal and interest payment to SCE in October 2006, which will be refunded to ratepayers through the ERRA mechanism. The settlement also permitted $58 million in liabilities that SCE had previously recorded with respect to the Duke terminated contracts to be reversed, which resulted in an equivalent benefit recorded by SCE in the third quarter of 2006 (reflected in the caption Purchased power on the income statement). The CPUC agreed that these liabilities should not be refunded to ratepayers. The recorded liabilities consisted of $40 million in cash collateral received from Duke in 2000 and $18 million in power purchase payments that SCE, in light of Duke s termination of the bilateral contracts, withheld for energy delivered by Duke in January 2001.

SCE: OTHER DEVELOPMENTS

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the U.S. District Court for the District of Columbia (District Court), against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organization (RICO) statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion.

In April 2004, the District Court dismissed SCE s motion for summary judgment and concluded that a 2003 U.S. Supreme Court decision in a related lawsuit by the Navajo Nation against the U.S. Government did not preclude the Navajo Nation from pursuing its RICO and intentional tort claims.

Pursuant to a joint request of the parties, the District Court granted a stay of the action on October 5, 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. An initial, organizational session was held with the facilitator on October 14, 2004 and negotiations are on-going. On July 28, 2005, the District Court issued an order removing the case from its active calendar, subject to reinstatement at the request of any party.

SCE cannot predict the outcome of the 1999 Navajo Nation s complaint against SCE, the ultimate impact on the complaint of the Supreme Court s 2003 decision and the on-going litigation by the Navajo Nation against the Government in the related case, or the impact on the facilitated negotiations of SCE s recently announced decision to discontinue efforts to return Mohave to service.

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Palo Verde Nuclear Generating Station Outage and Inspection

Between December 2005 when Palo Verde Unit 1 returned to service from its refueling and steam generator replacement outage and March 21, 2006, Palo Verde Unit 1 operated at between 25% and 32% power level. The need to operate at a reduced power level was due to the vibration level in one of the unit s shutdown cooling lines. On March 21, 2006, Arizona Public Service, the operating agent for Palo Verde Unit 1, decided to remove the unit from service completely. The vibration problem was resolved and Palo Verde Unit 1 was returned to service on July 7, 2006. Incremental replacement power costs are expected to be recovered through the ERRA rate-making mechanism.

The Nuclear Regulatory Commission (NRC) has held three special inspections of Palo Verde, between March 2005 and October 2006. A follow-up to the first inspection resulted in a finding that Palo Verde had not established adequate measures to ensure that certain corrective actions were effective. The second recent inspection identified five apparent violations that may require increased NRC regulatory oversight. The initial results of the most recent inspection concerning the failure of an emergency backup generator at Palo Verde Unit 3 are expected to be available in mid-November 2006. Multiple findings by the NRC of a need for increased regulatory oversight could increase the number of corrective actions Palo Verde would be required to take, thereby increasing costs. SCE cannot predict what corrective actions will have to be taken to satisfy these NRC inspection findings or the cost to Palo Verde s co-owners, including SCE.

SCE: MARKET RISK EXPOSURES

SCE s primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms. SCE uses derivative financial instruments, as appropriate, to manage its market risks. See SCE: Market Risk Exposures in the year-ended 2005 MD&A for a complete discussion of SCE s market risk exposures.

Commodity Price Risk

The following table summarizes the net fair values for outstanding physical and financial derivative investments used at SCE to mitigate its exposures to commodity price risk:

	September 30, 2006		December 31, 2005	
In millions	Assets	Liabilities	Assets	Liabilities
Energy options and tolling arrangements	$ 14	$	$ 25	$
Forward physicals (power)		121		49
Gas options, swaps and forward arrangements		146	105	
Total	$ 14	$ 267	$ 130	$ 49

SCE records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business SCE enters into contracts for power and gas options, as well as swaps and futures, in order to mitigate its exposure to increases in natural gas and electricity pricing. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes for recorded derivatives are recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses; therefore, fair value changes do not affect earnings. Hedge accounting is not used for these transactions due to this regulatory accounting treatment.

SCE recorded net unrealized losses of $9 million and $351 million, for the three- and nine-month periods ended September 30, 2006, respectively, compared to net unrealized gains of $504 million and $457 million, for the same periods in 2005, respectively. The 2006 quarter and year-to-date unrealized losses were primarily due to changes in both the gas and power portfolios, as well as decreases in the gas and power forward market prices.

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EDISON MISSION GROUP INC.

EMG has no business activities other than through its ownership interests in its subsidiaries, including MEHC (parent), EME, and Edison Capital. The following section includes discussion of liquidity, market risk exposures and other matters related to EMG s principal subsidiaries.

EMG: LIQUIDITY

MEHC (parent) s Liquidity

At September 30, 2006, MEHC had cash and cash equivalents of $15 million (excluding amounts held by EME and its subsidiaries). MEHC s ability to honor its obligations under the senior secured notes is substantially dependent upon the receipt of dividends from EME and the receipt of tax-allocation payments from EMG, and ultimately Edison International. See EME s Liquidity as a Holding Company Intercompany Tax-Allocation Agreement. Dividends to MEHC from EME are limited based on EME s earnings and cash flow, terms of restrictions contained in EME s corporate credit facility, business and tax considerations and restrictions imposed by applicable law.

Dividends to MEHC

In January 2006, EME made total dividend payments of $11.5 million to MEHC. In July 2006, EME made a dividend payment of $39 million to MEHC.

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.

MEHC s 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

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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 and $4 million of 9.875% 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.

MEHC s 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 nonenvironmental 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 EMG: Current Developments Environmental Developments Regarding Emissions.

MEHC s Credit Ratings

Overview

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

	Moody s Rating	S&P Rating
MEHC	B2	B
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 MEHC to B from B-. Standard & Poor s also raised the credit ratings 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.

MEHC 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. MEHC 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.

MEHC 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 Generation L.P. (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 EMG: Market Risk Exposures MEHC s Commodity Price Risk Energy Price Risk Affecting Sales from the Homer City Facilities.

MEHC s 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 MEHC s 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 MEHC s Dividend Restrictions in Major Financings.

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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 revenue 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.

In millions Nine Months Ended September 30,	**2006**	**2005**
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

MEHC (parent) and EME are included in the consolidated federal and combined state income tax returns of Edison International and are eligible to participate in tax-allocation payments with other subsidiaries of Edison International in circumstances where domestic tax losses are incurred. The right of MEHC (parent) and EME to receive and the amount of and timing of tax-allocation payments are dependent on the inclusion of MEHC (parent) and EME, respectively, 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 MEHC (parent), EME, its subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. MEHC (parent) and EME receive 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 MEHC (parent) s or

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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, MEHC (parent) and EME are obligated during periods they generate 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 the third quarter receipts) and received tax-allocation payments from Edison International of $52 million during the first nine months of 2005. MEHC (parent) received tax-allocation payments from Edison International of $30 million and $80 million, respectively, during the nine months ended September 30, 2005, respectively.

MEHC s 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 MEHC and EME s Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of MEHC and EME s principal subsidiaries required by financing arrangements for the twelve months ended September 30, 2006:

Subsidiary	Financial Ratio	Covenant	Actual
MEHC	Interest Coverage Ratio	Greater than 2.0 to 1	3.00 to 1
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 revenue 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 MEHC: Liquidity Dividend Restrictions in Major Financings in the year-ended 2005 MD&A.

Contingency

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

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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.

Edison Capital s Liquidity

Edison Capital s main sources of liquidity are tax-allocation payments from Edison International, distributions from its global infrastructure fund investments and lease rents. During the first nine months of 2006, Edison Capital received $130 million in tax-allocation payments and $41 million in global infrastructure fund distributions. As of September 30, 2006, Edison Capital had unrestricted cash and cash equivalents of $394 million and long-term debt, including current maturities, of $193 million.

Dividend Restrictions and Debt Covenants

Edison Capital s ability to make dividend payments to Edison International (parent) is restricted by debt covenants (see Edison International (Parent): Liquidity for further discussion). During the first nine months of 2006, Edison Capital complied with its debt covenants.

Intercompany Tax-Allocation Payments

Edison Capital 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 Edison International and other subsidiaries of Edison International. See EMG: Liquidity EME s Liquidity as a Holding Company Intercompany Tax-Allocation Agreement for additional information regarding these arrangements. The amount received is net of payments made to Edison International.

Edison Capital s Federal Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. Among the issues raised were items related to Edison Capital. See Other Developments Federal and State Income Taxes for further discussion of these matters.

EMG: 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.

MEHC s Commodity Price Risk

General Overview

EME s revenue 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.

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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 17 months and 29 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 Interconnection LLC (PJM) market.

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

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

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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 for 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.

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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]			
	Homer City		24-Hour PJM 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.

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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 revenue 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.

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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 Tons(1)				
In millions	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

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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 Other Developments Environmental Matters of the year-ended 2005 MD&A.

MEHC s 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 nonperforming counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of nonpayment 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:

In millions	September 30, 2006	
S&P Credit Rating:		
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.

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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 revenue 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 noninvestment 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 revenue.

MEHC s 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 MEHC s consolidated long-term obligations (including current portion) was $4.4 billion at September 30, 2006, compared to the carrying value of $4.0 billion. The fair market value of MEHC s parent only long-term obligations was $919 million at September 30, 2006, compared to the carrying value of $794 million.

MEHC s 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 nontrading 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 Less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 5 years
Prices actively quoted	$ 162	$ 88	$ 74	$	$

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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:

	September 30, 2006		December 31, 2005	
In millions	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 nonrecourse 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 Less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 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

MEHC s Regulatory Matters

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

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and many of its stakeholders, including EME, proposing a capacity market construct in PJM was submitted to the 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 25^{th} order. On May 17, 2006, FERC issued a notice extending the time for the MISO to comply with the requirements of the April 25^{th} 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.

Edison Capital s Market Risk Exposures

Edison Capital is exposed to interest rate risk, foreign currency exchange rate risk and credit and performance risk that could adversely affect its results of operations or financial position. See Edison Capital: Market Risk Exposures in the year-ended 2005 MD&A for a complete discussion of Edison Capital s market risk exposures.

EDISON INTERNATIONAL (PARENT)

EDISON INTERNATIONAL (PARENT): LIQUIDITY

The parent company s liquidity and its ability to pay interest and principal on debt, if any, operating expenses and dividends to common shareholders are affected by dividends and other distributions from subsidiaries, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to capital markets or external financings. As of September 30, 2006, Edison International had no debt outstanding (excluding intercompany related debt).

Edison International (parent) s cash requirements for the twelve-month period following September 30, 2006 primarily consist of:

- Dividends to common shareholders. Edison International paid quarterly common stock dividends of $88 million on January 31, 2006, April 30, 2006, July 31, 2006, and October 31, 2006;
- Intercompany related debt; and
- General and administrative expenses.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand, short-term borrowings, when necessary, and dividends from its subsidiaries. At September 30, 2006, Edison International (parent) had approximately $60 million of cash and cash equivalents on hand. In December 2005, Edison International (parent) replaced its $750 million credit facility with a $1 billion five-year senior unsecured credit facility. As of September 30, 2006, the entire $1 billion credit facility was available for liquidity purposes. The ability of subsidiaries to make dividend payments to Edison International is dependent on various factors as described below.

The CPUC regulates SCE s capital structure by requiring that SCE maintain prescribed percentages of common equity, preferred equity and long-term debt in the utility s capital structure. SCE may not make any distributions to Edison International that would reduce the common equity component of SCE s capital structure below the authorized level on a 13-month weighted average basis. The CPUC also requires that SCE establish its dividend policy as though it were a comparable stand-alone utility company and give first priority to the capital requirements of the utility as necessary to meet its obligation to serve its customers. Other factors at SCE that affect the amount and timing of dividend payments by SCE to Edison International include, among other things, SCE s capital requirements, SCE s access to capital markets, payment of dividends on SCE s preferred and preference stock, and actions by the CPUC. During 2006, SCE made dividend payments to Edison International of $71 million on January 16, 2006, and $60 million on each of April 28, 2006, July 24, 2006, and October 26, 2006.

MEHC may not pay dividends unless it has an interest coverage ratio of at least 2.0 to 1. At September 30, 2006, its interest coverage ratio was 3.0 to 1. See EMG: Liquidity MEHC s Dividend Restrictions in Major Financings Key Ratios of MEHC and EME s Principal Subsidiaries Affecting Dividends. In addition, MEHC s certificate of incorporation and senior secured note indenture contain restrictions on MEHC s ability to declare or pay dividends or distributions (other than dividends payable solely in MEHC s common stock). These restrictions require the unanimous approval of MEHC s Board of Directors, including its independent director, before it can declare or pay dividends or distributions, as long as any indebtedness is outstanding under the indenture. MEHC s ability to pay dividends is dependent on EME s ability to pay dividends to MEHC (parent). MEHC has not declared or made dividend payments to Edison International during the first nine months of 2006. EME and its subsidiaries have certain dividend restrictions as discussed in the EMG: Liquidity MEHC s Dividend Restrictions in Major Financings section.

Edison Capital s ability to make dividend payments is currently restricted by covenants in its financial instruments, which require Edison Capital, through a wholly owned subsidiary, to maintain a specified minimum net worth of $200 million. Edison Capital satisfied this minimum net worth requirement as of September 30, 2006. During 2006, Edison Capital made dividend payments of $102 million to Edison International.

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EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

Federal and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. See Other Developments Federal and State Income Taxes for further discussion of these matters.

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EDISON INTERNATIONAL (CONSOLIDATED)

The following sections of the MD&A are on a consolidated basis and should be read in conjunction with individual subsidiary discussion.

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

The following subsections of Results of Operations and Historical Cash Flow Analysis provide a discussion on the changes in various line items presented on the Consolidated Statements of Income, as well as a discussion of the changes on the Consolidated Statements of Cash Flows.

Results of Operations

Edison International recorded consolidated earnings of $458 million, or $1.38 per common share, for the three-month period ended September 30, 2006, compared to $462 million, or $1.41 per common share, for the comparable period in 2005.

Edison International recorded consolidated earnings of $893 million, or $2.71 per common share, for the nine-month period ended September 30, 2006, compared to $864 million, or $2.64 per common share, for the comparable period in 2005.

The table below presents Edison International s earnings and earnings per common share for the three- and nine-month periods ended September 30, 2006 and 2005, and the relative contributions by its subsidiaries.

In millions, except per common share amounts	Earnings (Loss)		Earnings (Loss) per Common Share	
Three-Month Period Ended September 30,	**2006**	**2005**	**2006**	**2005**
Earnings (Loss) from Continuing Operations:				
SCE	**$ 263**	$ 280	**$ 0.81**	$ 0.86
EMG:				
MEHC	**180**	155	**0.55**	0.48
Edison Capital and other	**24**	4	**0.07**	0.02
EMG Total	**204**	159	**0.62**	0.50
Edison International (parent) and other	**(7)**	(4)	**(0.04)**	(0.03)
Edison International Consolidated Earnings from Continuing Operations	**460**	435	**1.39**	1.33
Earnings (Loss) from Discontinued Operations	**(2)**	27	**(0.01)**	0.08
Edison International Consolidated	**$ 458**	$ 462	**$ 1.38**	$ 1.41

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In millions, except per common share amounts Nine-Month Period Ended September 30,	Earnings (Loss) 2006	 2005	Earnings (Loss) per Common Share 2006	 2005
Earnings (Loss) from Continuing Operations:				
SCE	**$ 618**	$ 572	**$ 1.90**	$ 1.75
EMG:				
MEHC	**177**	184	**0.54**	0.57
Edison Capital and other	**44**	77	**0.14**	0.23
EMG Total	**221**	261	**0.68**	0.80
Edison International (parent) and other	**(22)**	(24)	**(0.10)**	(0.08)
Edison International Consolidated Earnings from Continuing Operations	**817**	809	**2.48**	2.47
Earnings from Discontinued Operations	**75**	55	**0.23**	0.17
Cumulative Effect of Change in Accounting Principle	**1**			
Edison International Consolidated	**$ 893**	$ 864	**$ 2.71**	$ 2.64

Earnings (Loss) from Continuing Operations

Edison International s earnings from continuing operations were $460 million and $817 million for the three- and nine-month periods ended September 30, 2006, respectively, compared with earnings of $435 million and $809 million for the comparable periods in 2005.

SCE s earnings from continuing operations were $263 million and $618 million for the three- and nine-month periods ended September 30, 2006, respectively, compared with earnings of $280 million and $572 million for the comparable periods in 2005. The quarter and year-to-date variances reflect the impact of higher net revenue associated with the GRC decision and earnings from SCE s Mountainview plant, partially offset by higher income tax expense. Earnings from continuing operations for the three- and nine-month periods ended September 30, 2006 include a $24 million benefit from a generator settlement in 2006 (see SCE: Regulatory Matters Current Regulatory Developments Settlement Agreement with Duke Energy Trading and Marketing, LLC). Earnings from continuing operations for the nine-month period ended September 30, 2006, also include an $81 million benefit from the resolution of an outstanding state income tax issue (see SCE: Regulatory Matters Current Regulatory Developments 2006 General Rate Case Proceeding for further discussion of this benefit). Earnings from continuing operations for the three- and nine-month periods ended September 30, 2005 include a $61 million benefit from an IRS tax settlement and a $4 million generator refund incentive.

EMG s earnings from continuing operations were $204 million and $221 million for the three- and nine-month periods ended September 30, 2006, respectively, compared with earnings of $159 million and $261 million for the comparable periods in 2005. MEHC s earnings from continuing operations were $180 million and $177 million for the three-and nine-month periods ended September 30, 2006, respectively, compared to $155 million and $184 million for the same periods in 2005. The quarter increase was due to an after-tax impairment charge of $34 million related to the March Point project recorded in 2005 and favorable quarter over quarter results at MEHC s Homer City from derivative-related gains and losses and lower net corporate interest expense in 2006. The quarter increase was partially offset by lower income from energy trading and lower project income, primarily due to the Big Four and Doga. The year-to date decrease was due to an after-tax charge of $88 million in 2006 reflecting the early extinguishment of debt related to EME s debt refinancing, tax benefits recognized in 2005 and lower trading and project income primarily due to the Big Four and Doga in 2006. These decreases were partially offset by the March Point plant impairment of $34 million and a charge of $15 million related to an extinguishment of debt both in 2005, as well as lower net interest expense and higher wholesale energy margins mainly driven by higher prices at MEHC s Illinois plants in 2006. Edison Capital s earnings from continuing operations were $24 million and $44 million for the three- and nine-month periods ended September 30, 2006, respectively, compared to $4 million and $77 million for the same periods in 2005. The quarter increase was primarily due to Edison Capital s share of gains from its investment in the Emerging Europe Infrastructure Fund. The year-to-date decrease reflects the impact of higher gains in 2005 from its investment in the Emerging Europe Infrastructure Fund, partially offset by lower corporate expenses and net interest expense in 2006.

Operating Revenue

Electric Utility Revenue

The following table sets forth the major changes in electric utility revenue:

In millions	Three Months Ended September 30, 2006 vs. 2005	Nine Months Ended September 30, 2006 vs. 2005
Electric utility revenue		
Rate changes (including unbilled)	$ 593	$ 986
Sales volume changes (including unbilled)	211	297
Balancing account (over) undercollections	(675)	(371)
Sales for resale	(116)	(314)
SCE s variable interest entities	(26)	(25)
Other (including intercompany transactions)	8	51
Total	$ (5)	$ 624

SCE s retail sales represented approximately 90% of electric utility revenue for both the three- and nine-month periods ended September 30, 2006, respectively, compared to approximately 85% for both comparable periods in 2005. Due to warmer weather during the summer months, electric utility revenue during the third quarter of each year is generally significantly higher than other quarters.

Total electric utility revenue decreased $5 million and increased $624 million for the three and nine months ended September 30, 2006, respectively (as shown in the table above). The increases resulting from rate changes for both periods was mainly due to the rate change implemented on February 4, 2006, June 4, 2006, and August 1, 2006 (see SCE: Regulatory Matters Current Regulatory Developments Impact of Regulatory Matters on Customer Rates for further discussion of these rate changes). The increases in electric utility revenue resulting from sales volume changes was mainly due to an increase in kilowatt-hours (kWh) sold resulting from record heat conditions experienced in the third quarter of 2006, as well as, SCE providing a greater amount of energy to its customers from its own sources in 2006, compared to 2005. Balancing account (over) undercollections represents the difference between authorized revenue and recorded revenue subject to regulatory balancing account mechanisms. Recorded revenue (reflected in revenue from rate changes and sales volume changes in the table above) exceeded authorized revenue by approximately $767 million and $663 million in the three- and nine-month periods ended September 30, 2006, respectively, compared to approximately $92 million and $292 million in the same periods in 2005, respectively, due to higher balancing account overcollections in 2006, compared to 2005. Electric utility revenue from sales for resale represents the sale of excess energy. Excess energy from SCE sources which may exist at certain times is resold in the energy markets. Sales for resale revenue decreased due to a lesser amount of excess energy in 2006, as compared to 2005. Revenue from sales for resale is refunded to customers through the ERRA rate-making mechanism and does not impact earnings. SCE s variable interest entities revenue represents the recognition of revenue resulting from the consolidation of SCE s variable interest entities. The year-to-date increase in other revenue was due to higher investment earnings from SCE s nuclear decommissioning trusts. The nuclear decommissioning trust investment earnings are offset in depreciation, decommissioning and amortization expense and as a result, have no impact on net income.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE s customers, CDWR bond-related costs and a portion of direct access exit fees are remitted to the CDWR and none of these collections are recognized as revenue by SCE. These amounts were $686 million and $1.8 billion for the three- and nine-month periods ended September 30, 2006, respectively, compared to $534 million and $1.5 billion for the same respective periods in 2005.

Nonutility Power Generation Revenue

Nonutility power generation revenue increased $27 million and $69 million in the three- and nine-month periods ended September 30, 2006, respectively, as compared to the same periods in 2005.

Nonutility power generation revenue from MEHC s Illinois plants increased $20 million and $55 million for the three- and nine-month periods ended September 30, 2006, respectively, as compared to the same periods in 2005. The quarter increase was mainly due to decreased losses related to price risk management activities, partially offset by lower energy revenue. Although generation in the third quarter of 2006 was higher than in the third quarter of 2005, there was a 6% decrease in average energy prices. The year-to-date increase was mainly due to higher energy revenue driven by higher energy prices and decreased losses related to price risk management activities. Losses from price risk management activities are due to price changes on power contracts that did not qualify for hedge accounting treatment.

Nonutility power generation revenue from MEHC s Homer City facilities increased $31 million and $12 million for the three- and nine-month periods ended September 30, 2006. The quarter and year-to-date increases were primarily attributable to changes in net gains (losses) from price risk management activities, partially offset by lower energy revenue due to an unplanned outage. 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 outage reduced the amount of generation during the first nine months of 2006. See EMG: Current Developments MEHC: Homer City Transformer Failure for further discussion. Homer City recorded price risk management gains of $8 million and losses of $8 million for the three- and nine-month periods ended September 30, 2006, respectively, compared to losses of $32 million and $35 million during the comparable periods in 2005, representing the amount of cash flow hedges ineffectiveness. Losses related to the ineffective portion of hedge contracts were primarily due to changes in the difference between energy prices at the 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 from price risk management activities are economic hedges that did not qualify for hedge accounting treatment of $12 million and $15 million for the three- and nine-month periods ended September 30, 2006, respectively, and $10 million and $9 million for the comparable periods in 2005, respectively. See EMG: Market Risk Exposures MEHC s Commodity Price Risk for more information regarding forward market prices.

Revenue from energy trading activities at EMMT decreased $30 million and $16 million for the three- and nine-month periods ended September 30, 2006, respectively, as compared to the same periods in 2005. The decreases were primarily attributable to transmission less congestion in the Eastern power grid, due in part to lower wholesale energy prices driven by lower natural gas prices.

Due to higher electric demand resulting from warmer weather during the summer months and cold weather during the winter months, nonutility power generation revenue from MEHC s Illinois plants and Homer City facilities varies 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. Seasonal fluctuations may also be affected by changes in market prices. See EMG: Market Risk Exposures MEHC s 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.

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Operating Expenses

Fuel Expense

In millions	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
SCE	**$ 286**	$ 296	**$ 836**	$ 817
EMG MEHC	**200**	193	**490**	492
Edison International Consolidated	**$ 486**	$ 489	**$ 1,326**	$ 1,309

SCE s fuel expense decreased $10 million for the three months ended September 30, 2006 and increased $19 million for the nine months ended September 30, 2006, as compared to the same periods in 2005. The quarter and year-to-date variances were due to lower fuel expense of approximately $25 million and $60 million for the three- and nine-month periods ended September 30, 2006, respectively, at SCE s Mohave Generating Station resulting from the plant shutdown on December 31, 2005 (see SCE: Regulatory Matters Mohave Generating Station and Related Proceedings for further discussion); lower fuel expense of $50 million and $65 million for the three- and nine-month periods ended September 30, 2006, respectively, related to SCE s consolidated variable interest entities; and higher fuel expense of $65 million and $165 million for the three- and nine-month periods ended September 30, 2006, respectively, resulting from SCE s newly constructed Mountainview project which became operational in December 2005. The year-to-date variance also reflects lower nuclear fuel expense of $15 million resulting from a planned refueling and maintenance outage at SCE s San Onofre Unit 2.

Purchased-Power Expense

Purchased-power expense increased $534 million and $1.2 billion for the three- and nine-month period ended September 30, 2006, respectively, as compared to the same periods in 2005. The quarterly and year-to-date increases were mainly due to net realized and unrealized losses of $120 million and $630 million in the three- and nine-month periods ended September 30, 2006, respectively, compared to net realized and unrealized gains of $585 million and $530 million in the same periods in 2005, respectively (see SCE: Market Risk Exposures Commodity Price Risk for further discussion). The quarter increase was partially offset by lower firm energy purchases of approximately $40 million, lower power purchased from qualifying facilities (QF) of approximately $45 million (as further discussed below) and higher energy settlement refunds of approximately $115 million in 2006, compared to 2005. The year-to-date increase was also due to increased firm energy purchases of approximately $75 million and a decrease in power purchased from QFs of approximately $40 million.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. Energy payments to gas-fired QFs are generally tied to spot natural gas prices. Effective May 2002, energy payments for most renewable QFs were converted to a fixed price of 5.37¢-per-kWh until April 2007. Average spot natural gas prices were higher during 2006 as compared to 2005. The higher expenses related to power purchased from QFs were mainly due to higher average spot natural gas prices, partially offset by lower kWh purchases.

Provisions for Regulatory Adjustment Clauses Net

Provisions for regulatory adjustment clauses net decreased $651 million and $1.0 billion for the three- and nine-month periods ended September 30, 2006, as compared to the same periods in 2005. The decreases for both periods were mainly due to net unrealized losses related to economic hedging transactions (mentioned above in purchased-power expense) of approximately $10 million and $350 million for the three- and nine-month periods ended September 30, 2006, respectively, that, if realized, would be recovered from ratepayers, compared to unrealized gains of $505 million and $455 million for the same periods in 2005, respectively (see SCE: Market Risk Exposures Commodity Price Risk for further discussion). The decreases also reflect lower net

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overcollections of purchase-power, fuel, and operation and maintenance expenses of approximately $155 million and $40 million for the three- and nine-month periods ended September 30, 2006. The year-to-date decrease was also due to the resolution of the one-time issue related to a portion of revenue collected during the 2001 2003 period related to state income taxes. SCE was able to determine through the 2006 GRC decision and other regulatory proceedings that the level of revenue collected during that period was appropriate, and as a result recorded a pre-tax gain of $135 million.

Other Operation and Maintenance Expense

In millions	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
SCE	**$ 662**	$ 668	**$ 1,916**	$ 1,835
EMG MEHC	**181**	172	**605**	593
EMG Edison Capital and Other	**2**	10	**15**	41
Edison International (parent) and Other	**8**	12	**25**	28
Edison International Consolidated	**$ 853**	$ 862	**$ 2,561**	$ 2,497

SCE s other operation and maintenance expense increased $81 million for the nine-month period ended September 30, 2006, as compared to the same period in 2005. The year-to-date increase was mainly due to higher generation-related costs of approximately $50 million primarily resulting from the planned refueling and maintenance outage at SCE s San Onofre Unit 2, higher transmission and distribution maintenance cost of approximately $15 million, partially offset by a decrease of $15 million in reliability costs related to must-run offer units (reliability costs are being recovered through regulatory mechanisms approved by the FERC). In addition, as a result of implementation of the 2006 GRC, beginning in May 2006, costs related to the Mohave shutdown, postretirement benefits other than pensions, pensions and results sharing are being recovered through a balancing account mechanism.

Depreciation, Decommissioning and Amortization Expense

In millions	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
SCE	**$ 254**	$ 234	**$ 806**	$ 688
EMG MEHC	**36**	30	**104**	91
EMG Edison Capital and Other	**3**	6	**14**	17
Edison International Consolidated	**$ 293**	$ 270	**$ 924**	$ 796

SCE s depreciation, decommissioning and amortization expense increased $20 million and $118 million for the three- and nine-month periods ended September 30, 2006, respectively, as compared to the same periods in 2005. The increases in 2006 are mainly due to an increase in depreciation expense resulting from additions to transmission and distribution assets, as well as an increase of approximately $15 million and $50 million for the three- and nine-month periods ended September 30, 2006, respectively, resulting from the implementation of the new depreciation rates approved in the 2006 GRC decision, and higher investment earnings from SCE s nuclear decommissioning trusts. The nuclear decommissioning trust investment earnings are also recorded in electric utility revenue and as a result, have no impact on net income.

Other Income and Deductions

Interest and Dividend Income

SCE s interest and dividend income increased $7 million for the nine-month period ended September 30, 2006, as compared to the same period in 2005. The 2006 increase was mainly due to higher interest income resulting from higher balancing account undercollections and higher short-term interest rates in 2006, as compared to 2005.

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MEHC s interest and dividend income increased $11 million and $27 million for the three- and nine-month periods ended September 30, 2006, respectively, as compared to the same periods in 2005, primarily due to higher interest rates in 2006, compared to 2005.

Equity in Income from Partnerships and Unconsolidated Subsidiaries Net

Equity in income from partnerships and unconsolidated subsidiaries net decreased $83 million for the nine-month period ended September 30, 2006. The 2006 decrease is mainly due to lower earnings of approximately $65 million from Edison Capital s global infrastructure funds due to higher gains in 2005.

Other Nonoperating Income

SCE s other nonoperating income decreased $20 million and $7 million for the three- and nine-month periods ended September 30, 2006, as compared to the same periods in 2005. The decrease in both periods was mainly due to a $15 million incentive recorded in 2005 related to demand-side management and energy efficiency performance for the portion of the incentive previously collected in rates, but which were deferred. There was no comparable incentive in 2006. Also recorded in other nonoperating income are incentive rewards approved by the CPUC for the efficient operation of Palo Verde of $15 million in the first quarter of 2006 and $10 million in the first quarter of 2005.

MEHC s other nonoperating income increased $25 million for the nine-months ended September 30, 2006, as compared to the same period in 2005. The year-to-date increase was due to the recognition of an estimated business interruption insurance claim in the amount of $10 million and an $8 million gain related to the receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter 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.

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt for the nine-month period ended September 30, 2006 of $143 million relates to the early repayment of substantially all of EME s 10% senior notes due August 15, 2008 and 9.875% senior notes due April 15, 2011. The loss on early extinguishment for the nine-month period ended September 30, 2005 of $24 million primarily relates to the early repayment of MEHC s $385 million term loan.

Other Nonoperating Deductions

Other nonoperating deductions decreased $22 million and $23 million for the three- and nine-month periods ended September 30, 2006, respectively, mainly due to a 2005 penalty accrual of $26 million under the system reliability performance mechanism for 2005.

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Income Tax (Benefit) Continuing Operations

In millions	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
SCE	**$ 187**	$ 52	**$ 416**	$ 176
EMG MEHC	**124**	95	**105**	89
EMG Edison Capital and Other	**2**	(13)	**1**	5
Edison International (parent) and Other	**(3)**	(5)	**(6)**	(3)
Edison International Consolidated	**$ 310**	$ 129	**$ 516**	$ 267

Edison International s effective tax rate from continuing operations was 40% and 39% for the three- and nine-month periods ended September 30, 2006, respectively, as compared to 23% and 25% for the same periods in 2005. The increased effective tax rate resulted primarily from recording a $65 million benefit, including $57 million of interest income, in the third quarter of 2005 related to a settlement with the IRS on tax issues and pending affirmative claims relating to Edison International s 1991 1993 tax years. Additional increases to the effective tax rate resulted from reductions made to SCE s income tax reserve in 2005 to reflect the issuance of new IRS regulations and progress in settlement negotiations relating to tax audits other than the 1991 1993 IRS audit, and adjustments made to tax balances in 2005 at both MEHC and SCE.

Income from Discontinued Operations

Edison International recorded a loss from discontinued operations of $2 million and income of $75 million for the three- and nine-month periods ended September 30, 2006, respectively, compared to income of $27 million and $55 million for the same periods in 2005. The 2006 year-to-date income primarily resulted from distributions from MEHC s Lakeland Project. The 2005 year-to-date income reflects positive tax adjustments of $28 million related to the sale of MEHC s international projects and $24 million of distributions received from MEHC s Lakeland project (see EMG: Current Developments MEHC: Lakeland Project for further discussion).

Cumulative Effect of Accounting Change Net of Tax

Effective January 1, 2006, Edison International adopted a new accounting standard that requires the fair value accounting method for stock-based compensation. Implementation of this new accounting standard resulted in a $1 million, after-tax, cumulative-effect adjustment in the first quarter of 2006 (see New Accounting Pronouncements for further discussion).

Historical Cash Flow Analysis

The Historical Cash Flow Analysis section of this MD&A discusses consolidated cash flows from operating, financing and investing activities.

Cash Flows from Operating Activities

Net cash provided by operating activities:

In millions Nine Months Ended September 30,	2006	2005
Continuing operations	**$ 2,888**	$ 1,705
Discontinued operations	**82**	22
	$ 2,970	$ 1,727

The 2006 change in cash provided by operating activities from continuing operations was mainly due to an increase in cash collected from SCE s customers due to increased rates (see SCE: Regulatory Matters Current Regulatory Developments Impact of Regulatory Matters on Customer Rates) and increased sales volume due to warmer weather in 2006, as compared to 2005, which contributed to higher balancing account overcollections in 2006, as compared to 2005. The 2006 increase was also attributable to a decrease of $462 million in required margin and collateral deposits in 2006 mainly for MEHC s price risk management and trading activities, compared to an increase of $413 million in 2005. The 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 $61 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 MEHC s Lakeland power project. See Current Developments EMG: Current Developments MEHC: Lakeland Project for more information regarding these distributions.

Cash Flows from Financing Activities

Net cash used by financing activities:

In millions Nine Months Ended September 30,	**2006**	**2005**
Continuing operations	$ (673)	$ (955)

Cash used by financing activities from continuing operations mainly consisted of long-term and short-term debt payments at SCE and EME.

Financing activities in 2006 included activities related to the rebalancing of SCE s capital structure and rate base growth and the reduction of debt at MEHC.

In January 2006, SCE issued $500 million of first and refunding mortgage bonds which consisted of $350 million of 5.625% bonds due in 2036 and $150 million of floating rate bonds due in 2009. The proceeds from this issuance were used to redeem $150 million of variable rate first and refunding mortgage bonds due in January 2006 and $200 million of its 6.375% first and refunding mortgage bonds due in January 2006.

In January 2006, SCE issued two million shares of 6% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of $197 million.

In June 2006, EME issued $1 billion of senior notes. The proceeds from this issuance were mostly used to repay $965 million of EME s outstanding senior notes and $136 million paid for tender premiums and related fees.

During the nine months ended September 30, 2006, Midwest Generation had borrowings of $395 million under its credit facility, mostly offset by repayments of $535 million.

Financing activities in 2006 also included dividend payments of $264 million paid by Edison International to its shareholders.

Financing activities in 2005 also included activities related to the rebalancing of SCE s capital structure and the reduction of debt at MEHC.

In January 2005, SCE issued $650 million of first and refunding mortgage bonds which consisted of $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds from this issuance were used to redeem the remaining $50,000 of its 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and $650 million of the $966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B).

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In January 2005, MEHC repaid the remaining $285 million of its term loan.

In January 2005, MEHC repaid $150 million of its junior subordinated debentures.

In April 2005, SCE issued 4,000,000 shares of Series A preference stock (noncumulative, 100% liquidation value) and received net proceeds of approximately $394 million. Approximately $81 million of the proceeds was used to redeem all the outstanding shares of its $100 cumulative preferred stock, 7.23% Series, and approximately $64 million of the proceeds was used to redeem all the outstanding shares of its $100 cumulative preferred stock, 6.05% Series.

In April 2005, MEHC repaid $302 million related to Midwest Generation s existing term loan.

In June 2005, SCE issued $350 million of 5.35% first and refunding mortgage bonds due in 2035 (Series 2005E). A portion of the proceeds from this issuance were used to redeem $316 million of its 8% first and refunding mortgage bonds due in 2007 (Series 2003B).

Financing activities in 2005 also include dividend payments of $244 million paid by Edison International to its shareholders.

Cash Flows from Investing Activities

Net cash provided (used) by investing activities:

In millions Nine Months Ended September 30,	2006	2005
Continuing operations	**$ (1,986)**	$ (891)
Discontinued operations		5
	$ (1,986)	$ (886)

Cash flows from investing activities are affected by capital expenditures, EME s sales of assets and SCE s funding of nuclear decommissioning trusts.

Investing activities in 2006 reflect $1.6 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $63 million for nuclear fuel acquisitions, and $142 million in capital expenditures at MEHC. In addition, investing activities include net purchases of marketable securities of $184 million at MEHC and received proceeds of $43 million from the sale of 25% of EME s ownership interest in the San Juan Mesa wind project.

Investing activities in 2005 reflect $1.3 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $43 million for nuclear fuel acquisitions and $111 million related to the Mountainview project, and $42 million in capital expenditures at MEHC. In addition, investing activities include net purchases of marketable securities of $140 million at MEHC and $124 million in proceeds received in 2005 from the sale of EME s 25% investment in the TriEnergy project and EME s 50% investment in the CBK project.

ACQUISITIONS AND DISPOSITIONS

Acquisition

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-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

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2006 and is scheduled for completion in 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 nonutility property in Edison International s consolidated balance sheet.

Disposition

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.

NEW ACCOUNTING PRONOUNCEMENTS

A new accounting standard, Statement of Financial Accounting Standards (SFAS) No. 123(R), requires companies to use the fair value accounting method for stock-based compensation. Edison International 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, Edison International used the intrinsic value method of accounting, which resulted in no recognition of expense for its stock options. Prior to adoption of the new accounting standard, Edison International presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption Other 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 $18 million excess tax benefit is classified as a financing cash inflow in 2006. Due to the adoption of this new accounting standard, Edison International recorded a cumulative effect adjustment that increased net income by approximately $1 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.

In April 2006, the Financial Accounting Standards Board (FASB) issued a Staff Position (FSP), FSP FIN 46(R)-6, that specifies how a company should determine the variability to be considered in applying the accounting standard for consolidation of variable interest entities. The pronouncement states that such variability shall be determined based on an analysis of the design of the entity, including the nature of the risks in the entity, the purpose for which the entity was created, and the variability the entity is designed to create and pass along to its interest holders. This new accounting guidance was effective prospectively beginning July 1, 2006, although companies have until December 31, 2006, to elect retrospective application. Edison International has not yet selected a transition method. Applying the guidance of FSP FIN 46(R)-6 had no effect on the financial statements for the three months ended September 30, 2006.

In July 2006, the FASB issued an interpretation (FIN 48) relating to accounting for uncertainty in income taxes. This interpretation 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 is January 1, 2007. Edison International is currently assessing the potential impact of FIN 48 on its financial condition.

In July 2006, the FASB issued an FSP on accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction (FSP FAS 13-2). The effective date is January 1, 2007. As discussed under Other Developments Federal and State Income Taxes, the deferral of

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income taxes associated with Edison Capital s cross-border, leveraged leases has been challenged by the IRS. If it becomes probable that Edison International would accelerate the payment of deferred taxes for these leases, the new FSP requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

In September 2006, the FASB issued a new accounting standard on fair value measurements (SFAS 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. Edison International will adopt SFAS No. 157 on January 1, 2008. Edison International is currently evaluating the impact of adopting SFAS No. 157 on its financial statements.

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 its balance sheet; the asset or liability is offset through other comprehensive income. Edison International will record regulatory assets or liabilities instead of charges or credits to other comprehensive income for its postretirement benefit plans that are recoverable in utility rates, in accordance with accounting principles for rate-regulated enterprises. The standard also requires companies to align the measurement dates for their plans to their fiscal year-ends; Edison International already has a fiscal year-end measurement date for all of its postretirement plans. Edison International will adopt SFAS No. 158 prospectively on December 31, 2006. Had SFAS No. 158 been effective as of December 31, 2005, Edison International would have recorded additional postretirement benefit liabilities of $773 million, additional regulatory assets of $723 million, and a reduction to accumulated other comprehensive income (a component of shareholders equity) of $31 million, net of tax. Edison International is currently assessing the impact of this standard on its 2006 financial statements.

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. The new guidance requires additional quantitative testing to determine whether a misstatement is material. Edison International will implement SAB No. 108 for the filing of its Annual Report on Form 10-K for the year ended December 31, 2006. Edison International is currently assessing the impact, if any, of the adoption of SAB No. 108.

In September 2006, the FASB s Emerging Issues Task Force (EITF) reached a consensus for Issue No. 06-5, which clarifies the accounting for purchases of life insurance, including corporate-owned life insurance. The new guidance states that policyholders should consider any additional amounts included in the contractual terms of the policy in determining the amount that could be realized under the insurance contract, and specifies that contractual limitations should be considered when determining the realizable amounts. The new guidance is effective January 1, 2007, and retrospective application or a cumulative effect adjustment is permitted to transition to the new guidance. Edison International is currently evaluating the impact, if any, of adopting EITF Issue No. 06-5.

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COMMITMENTS, GUARANTEES AND INDEMNITIES

The following is an update to Edison International s commitments, guarantees and indemnities. See the section, Commitments, Guarantees and Indemnities, in the year-ended 2005 MD&A for a detailed discussion.

Lease Commitments

Estimated remaining commitments (the majority of which are related to EME s long-term leases for the Powerton, Joliet and Homer City power plants) for noncancelable operating leases at September 30, 2006 are:

In millions	
	(Unaudited)
October through December 2006	$ 124
2007	704
2008	675
2009	611
2010	566
Thereafter	3,056
Total	$ 5,736

Other Commitments

Edison International s long-term principal debt maturities and sinking-fund requirements as of September 30, 2006 are: remaining 2006 $106 million; 2007 $487 million; 2008 $878 million; 2009 $763 million; 2010 $314 million; and thereafter $6.8 billion.

The following commitments provide further details of certain capital expenditures included in the EMG: Liquidity MEHC S Capital Expenditures discussion:

At September 30, 2006, EME s subsidiaries had firm commitments to spend approximately $260 million during the remainder of 2006 and $117 million in 2007 on capital and construction expenditures. The majority of these expenditures relate to the construction of the 161-MW Wildorado wind project (see further discussion related to the Wildorado project in Acquisitions and Dispositions) and four other wind projects totaling 181 MW. Also included are expenditures for boiler head replacement, dust collection and mitigation system, and various other smaller projects. These expenditures are planned to be financed by cash on hand or cash generated from operations or existing subsidiary credit agreements.

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.

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OTHER DEVELOPMENTS

Environmental Matters

The operating affiliates of Edison International are subject to numerous federal and state environmental laws and regulations, which require them to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment. Edison International believes that its operating affiliates are in substantial compliance with existing environmental regulatory requirements.

The domestic power plants owned or operated by Edison International s operating affiliates, in particular their coal-fired plants, may be affected by recent developments in federal and state environmental laws and regulations. These laws and regulations, including those relating to sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions, mercury emissions, ozone and fine particulate matter emissions, regional haze, water quality, and climate change, may require significant capital expenditures at these facilities. The developments in certain of these laws and regulations are discussed in more detail below. These developments will continue to be monitored to assess what implications, if any, they will have on the operation of domestic power plants owned or operated by SCE, EME, or their subsidiaries, or the impact on Edison International s results of operations or financial position.

For a discussion of Edison International s environmental matters, refer to Other Developments Environmental Matters in the year-ended 2005 MD&A. There have been no significant developments with respect to environmental matters affecting Edison International since the filing of Edison International s Annual Report on Form 10-K, except as follows:

Federal Air Quality Standards

Clean Air Mercury Rule

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.

State Air Quality Standards

On March 14, 2006, the Illinois Environmental Protection Agency submitted a proposed rule for reduction of mercury emissions to the Illinois Pollution Control Board (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

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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 must now 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 nonattainment 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.

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.

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California Greenhouse Gas Emissions Legislation

In September 2006, California s Governor Schwarzenegger signed two bills into law regarding greenhouse gas emissions. The first, known as Assembly Bill 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. Assembly Bill 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 Senate Bill 1368, requires the CEC to develop and adopt by regulation a greenhouse gas emissions performance standard for long-term procurement of electricity by local publicly owned utilities. The CEC must adopt the standard on or before June 30, 2007 and it must be consistent with the standard to be adopted by the CPUC for load-serving entities under their jurisdiction on or before February 1, 2007. For more information on the CPUC standard, refer to Other Developments Environmental Matters Environmental Matters Affecting SCE Climate Change in the year-ended 2005 MD&A. Edison International is not able at this time to predict the final form of these rules or provide an estimate of their financial impact.

Environmental Remediation

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

Edison International s recorded estimated minimum liability to remediate its 35 identified sites at SCE (23 sites) and EME (12 sites related to Midwest Generation) is $87 million, $84 million of which is related to SCE. Edison International s other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International s identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $116 million, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 32 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $8 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $35 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $85 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International s identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that Edison

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International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $25 million. Recorded costs for the twelve months ended September 30, 2006 were $13 million.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC s regulatory treatment of environmental remediation costs incurred at SCE, Edison International believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 1996 and 1997 1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would be deductible on future tax returns of Edison International. Edison International has also submitted affirmative claims to the IRS and state tax agencies which are being addressed in administrative proceedings. Any benefits would be recorded when a settlement is reached or as part of the implementation of FIN 48.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes associated with Edison Capital s cross-border, leveraged leases.

The IRS is challenging Edison Capital s foreign power plant and electric locomotive sale/leaseback transactions entered into in 1993 and 1994 (Replacement Leases, which the IRS refers to as a sale-in/lease-out or SILO). The IRS is also challenging Edison Capital s foreign power plant and electric transmission system lease/leaseback transactions entered into in 1997 and 1998 (Lease/Leaseback, which the IRS refers to as a lease-in/lease-out or LILO).

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (Service Contract, which the IRS also refers to as a SILO). The IRS did not yet assert an adjustment for the Service Contract but is expected to challenge the Service Contract in subsequent audit cycles.

The following table summarizes estimated federal and state income taxes deferred from these leases. Repayment of these deferred taxes would be accelerated if the IRS prevails:

In millions	Tax Years Under Appeal 1994 1999	Unaudited Tax Years 2000 2005	Total
Replacement Leases (SILO)	$ 44	$ 36	$ 80
Lease/Leaseback (LILO)	558	570	1,128
Service Contract (SILO)		272	272
	$ 602	$ 878	$ 1,480

As of September 30, 2006, the interest on the proposed tax adjustments is estimated to be approximately $386 million. The IRS also seeks a 20% penalty on any sustained tax adjustment.

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Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into, and it is vigorously defending its tax treatment of these leases. Written protests were filed to appeal the audit adjustments for the tax years under appeal asserting that the IRS s position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS.

In addition, the payment of taxes, interest and penalties could have a significant impact on earnings and cash flow. In order to commence litigation in certain forums, Edison International must make payments of disputed taxes, along with interest and any penalties asserted by the IRS, and thereafter pursue refunds. On May 26, 2006 Edison International paid $111 million of the taxes, interest, and penalties for tax year 1999 followed by a refund claim for the same amount. The cash payment was funded by Edison Capital and accounted for as a deposit which will be refunded with interest to the extent Edison International prevails. If the IRS either denies this refund claim or fails to act on the claim within six months, Edison International expects to take legal action to assert its refund claim. Depending on the status of the claim for tax year 1999, Edison International may make additional payments related to other tax years to preserve its litigation rights, although, at this time, the amount and timing of these additional payments is uncertain. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters. See EMG: Liquidity Edison Capital s Liquidity.

Under an FSP on accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction and a FASB interpretation relating to accounting for uncertainty in income taxes, both issued in July 2006 and effective January 1, 2007, the payments made by Edison International will continue to be treated as a deposit unless it becomes more likely than not that a tax payment related to the resolution of the dispute will be made. If it becomes probable that such a tax payment will be made, the new FSP requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

The IRS Revenue Agent Report for the 1997 1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged lease transactions and the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest, retaining its appeal rights.

Enterprise-Wide Software System Project

Edison International has commenced an enterprise-wide project to implement a comprehensive, integrated software system to support the majority of its critical business processes during the next few years. The objective of this initiative is to improve the efficiency and effectiveness of both SCE s and EMG s operations and enhance the transparency of information.

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 (Midway-Sunset), which owns a 225 MW cogeneration facility near

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Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC because Midway-Sunset was a seller in the PX and ISO 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 PX and ISO markets, Midway-Sunset is potentially liable for refunds to purchasers in these markets. See SCE: Regulatory Matters Current Regulatory Developments FERC Refund Proceedings.

The claims asserted against Midway-Sunset for refunds related to power sold into the PX and ISO 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 did not retain any proceeds from power sold into the PX and ISO 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 through those proceeds to the utilities. Since the proceeds were passed through 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 PX and ISO markets on their behalves.

During this period, amounts SCE received from Midway-Sunset were credited to SCE s customers against power purchase expenses through the ratemaking mechanism in place at that time. SCE believes that any net amounts reimbursed to Midway-Sunset would be substantially recoverable from its customers through current regulatory mechanisms. Edison International does not expect any refund payment made by Midway-Sunset, or any SCE reimbursement to Midway-Sunset, to have a material impact on earnings.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Part I, Item 3 is included in Part I, Item 2, Management s Discussion and Analysis of Financial Condition and Results of Operations, under the headings SCE: Market Risk Exposures, EMG: Market Risk Exposures, and Edison International (Parent): Market Risk Exposures.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

Edison International s management, under the supervision and with the participation of the company s Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of Edison International s disclosure controls and procedures (as that 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, Edison International s disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

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

PART II OTHER INFORMATION

Item 1. Legal Proceedings

FERC Notice Regarding Investigatory Proceeding Against EMMT

Information about the FERC notice regarding an investigatory proceeding against EMMT appears in the MD&A under the heading EMG: Liquidity Contingency FERC Notice Regarding Investigatory Proceeding Against EMMT.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table contains information about all purchases made by or on behalf of Edison International or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) of shares or other units of any class of Edison International s equity securities that is registered pursuant to Section 12 of the Exchange Act.

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
July 1, 2006 to July 31, 2006	354,936	$ 40.02		
August 1, 2006 to August 31, 2006	353,784	$ 42.18		
September 1, 2006 to September 30, 2006	514,760	$ 42.38		
Total	1,223,480	$ 41.64		

[1] The shares were purchased by agents acting on Edison International s behalf for delivery to plan participants to fulfill requirements in connection with Edison International s (i) 401(k) Savings Plan, (ii) Dividend Reinvestment and Direct Stock Purchase Plan, and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were never registered in Edison International s name and none of the shares purchased were retired as a result of the transactions.

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Item 6. Exhibits

Edison International

2006

orth America, Inc., as Syndication Agent, and Credit Suisse First Boston, Lehman Commercial Paper Inc., and Wells Fargo Bank, N.A., as Documentation Agents, da

* Incorporated herein by reference pursuant to Rule 12b-32.

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SIGNATURE

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 INTERNATIONAL
(Registrant)

By /s/ LINDA G. SULLIVAN
LINDA G. SULLIVAN

Vice President and Controller

(Duly Authorized Officer and

Principal Accounting Officer)

Dated: November 3, 2006