EDISON INTERNATIONAL
Form 10-Q
November 07, 2008
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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, 2008

¨ **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	
(P. O. Box 976)	
Rosemead, California	**91770**
(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 ¨	Smaller reporting company ¨
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No 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 November 5, 2008**
Common Stock, no par value	**325,811,206**

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GLOSSARY

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

AB	Assembly Bill
AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
Btu	British thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
Commonwealth Edison	Commonwealth Edison Company
CDWR	California Department of Water Resources
CEC	California Energy Commission
CONE	Cost of new entry
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
CRRs	Congestion revenue rights
D.C. District Court	U.S. District Court for the District of Columbia
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPV2	Devers-Palo Verde II
DRA	Division of Ratepayer Advocates
DWP	Los Angeles Department of Water & Power
EME	Edison Mission Energy
EME Homer City	EME Homer City Generation L.P.
EMG	Edison Mission Group Inc.
EMMT	Edison Mission Marketing & Trading, Inc.
EPS	earnings per share
ERRA	energy resource recovery account
Exelon Generation	Exelon Generation Company LLC
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGIC	Financial Guarantee Insurance Company
FIN 39-1	Financial Accounting Standards Board Interpretation No. 39-1, Amendment of FASB Interpretation No. 39
FIN 48	Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FAS 109
FSP SFAS No. 133-1 and FIN No. 45-4	Financial Accounting Standards Board Staff Position No. 133-1 and FIN No. 45-4, Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161.
FSP SFAS 142-3	FASB Staff Position No. SFAS 142-3, Determination of the Useful Life of Intangible Assets
GAAP	general accepted accounting principles
GHG	greenhouse gas
Global Settlement	A settlement currently being negotiated between Edison International and the IRS, which, if consummated, would resolve asserted deficiencies related to Edison International s deferral of income taxes associated with certain of its cross-border, leveraged leases and all other outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. There can be no assurance about the timing of such settlement or that a final settlement will be ultimately consummated.

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GLOSSARY (Continued)

GRC	General Rate Case
GWh	gigawatt-hours
Illinois plants	EME s largest power plants (fossil fuel) located in Illinois
IRS	Internal Revenue Service
ISO	California Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Management s Discussion and Analysis of Financial Condition and Results of Operations
MEHC	Mission Energy Holding Company
Midway-Sunset	Midway-Sunset Cogeneration Company
Midwest Generation	Midwest Generation, LLC
MMBtu	million British thermal units
Mohave	Mohave Generating Station
Moody s	Moody s Investors Service
MRTU	Market Redesign and Technology Upgrade
MW	Megawatts
MWh	megawatt-hours
NOV	notice of violation
NO_x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator
Palo Verde	Palo Verde Nuclear Generating Station
PBOP(s)	Postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
POD	Presiding Officer s Decision
PRB	Powder River Basin
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RICO	Racketeer Influenced and Corrupt Organization
ROE	return on equity
RPM	reliability pricing model
S&P	Standard & Poor s
SCAQMD	South Coast Air Quality Management District
San Onofre	San Onofre Nuclear Generating Station
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS No. 141(R)	Statement of Financial Accounting Standards No. 141(R), Business Combinations
SFAS No. 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements
SFAS No. 158	Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans
SFAS No. 159	Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities

GLOSSARY (Continued)

SFAS No. 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements
SFAS No. 161	Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133
SIP(s)	State Implementation Plan(s)
SO_2	sulfur dioxide
TURN	The Utility Reform Network
US EPA	United States Environmental Protection Agency
VIE(s)	variable interest entity(ies)

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EDISON INTERNATIONAL

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

CONSOLIDATED STATEMENTS OF INCOME

In millions, except per-share amounts	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
		(Unaudited)		
Electric utility	**$ 3,284**	$ 3,213	**$ 8,388**	$ 7,895
Nonutility power generation	**813**	711	**2,143**	1,952
Financial services and other	**14**	18	**45**	55
Total operating revenue	**4,111**	3,942	**10,576**	9,902
Fuel	**635**	502	**1,725**	1,425
Purchased power	**1,962**	1,284	**3,111**	2,431
Provisions for regulatory adjustment clauses net	**(737)**	(66)	**(286)**	189
Other operation and maintenance	**1,025**	1,013	**3,109**	2,893
Depreciation, decommissioning and amortization	**262**	310	**893**	937
(Gain) on buyout of contract and (gain)/loss on sale of assets	**(1)**	1	**(75)**	
Total operating expenses	**3,146**	3,044	**8,477**	7,875
Operating income	**965**	898	**2,099**	2,027
Interest and dividend income	**9**	40	**44**	125
Equity in income from partnerships and unconsolidated subsidiaries net	**31**	35	**40**	72
Other nonoperating income	**23**	35	**78**	75
Interest expense net of amounts capitalized	**(176)**	(191)	**(511)**	(577)
Loss on early extinguishment of debt				(241)
Other nonoperating deductions	**(82)**	(7)	**(115)**	(31)
Income from continuing operations before tax and minority interest	**770**	810	**1,635**	1,450
Income tax expense	**277**	263	**521**	392
Dividends on preferred and preference stock of utility not subject to mandatory redemption	**13**	13	**38**	38
Minority interest	**47**	69	**77**	134
Income from continuing operations	**433**	465	**999**	886
Income (loss) from discontinued operations net of tax	**6**	(4)		1
Net income	**$ 439**	$ 461	**$ 999**	$ 887
Weighted-average shares of common stock outstanding	**326**	326	**326**	326
Basic earnings (loss) per common share:				
Continuing operations	**$ 1.31**	$ 1.41	**$ 3.03**	$ 2.69
Discontinued operations	**0.02**	(0.01)		
Total	**$ 1.33**	$ 1.40	**$ 3.03**	$ 2.69
Weighted-average shares, including effect of dilutive securities	**328**	330	**329**	331
Diluted earnings (loss) per common share:				
Continuing operations	**$ 1.31**	$ 1.40	**$ 3.02**	$ 2.67
Discontinued operations	**0.02**	(0.01)		
Total	**$ 1.33**	$ 1.39	**$ 3.02**	$ 2.67
Dividends declared per common share	**$ 0.305**	$ 0.29	**$ 0.915**	$ 0.87

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

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In millions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Unaudited)			
Net income	**$ 439**	$ 461	**$ 999**	$ 887
Other comprehensive income (loss), net of tax:				
Foreign currency translation adjustments-net	**(1)**	1	**(4)**	(1)
Pension and postretirement benefits other than pensions:				
Amortization of net gain (loss) and prior service cost included in expense-net				1
Unrealized gains (losses) on cash flow hedges:				
Other unrealized gains (losses) arising during the period net of income tax expense (benefit) of $357 and $(17) for the three months and $53 and $(102) for the nine months ended September 30, 2008 and 2007, respectively	**535**	(28)	**81**	(149)
Reclassification adjustments included in net income net of income tax expense (benefit) of $(44) and $8 for the three months and $45 and $27 for the nine months ended September 30, 2008 and 2007, respectively	**(65)**	12	**69**	38
Other comprehensive income (loss)	**469**	(15)	**146**	(111)
Comprehensive income	**$ 908**	$ 446	**$ 1,145**	$ 776

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

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CONSOLIDATED BALANCE SHEETS

In millions	September 30, 2008 (Unaudited)	December 31, 2007
ASSETS		
Cash and equivalents	$ 3,464	$ 1,441
Short-term investments	23	81
Receivables, less allowance of $33 and $34 for uncollectible accounts at respective dates	1,339	1,033
Accrued unbilled revenue	518	370
Fuel inventory	138	116
Materials and supplies	376	316
Derivative assets	232	109
Restricted cash	3	3
Margin and collateral deposits	157	121
Regulatory assets	454	197
Accumulated deferred income taxes net	190	167
Other current assets	189	290
Total current assets	7,083	4,244
Nonutility property less accumulated provision for depreciation of $1,949 and $1,765 at respective dates	5,257	4,906
Nuclear decommissioning trusts	2,855	3,378
Investments in partnerships and unconsolidated subsidiaries	260	272
Investments in leveraged leases	2,460	2,473
Other investments	110	96
Total investments and other assets	10,942	11,125
Utility plant, at original cost:		
Transmission and distribution	19,776	18,940
Generation	1,820	1,767
Accumulated provision for depreciation	(5,526)	(5,174)
Construction work in progress	1,970	1,693
Nuclear fuel, at amortized cost	246	177
Total utility plant	18,286	17,403
Derivative assets	206	122
Restricted cash	43	48
Rent payments in excess of levelized rent expense under plant operating leases	878	716
Regulatory assets	2,880	2,721
Other long-term assets	1,348	1,144
Total long-term assets	5,355	4,751
Total assets	$ 41,666	$ 37,523

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

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EDISON INTERNATIONAL

CONSOLIDATED BALANCE SHEETS

In millions, except share amounts	September 30, 2008 (Unaudited)	December 31, 2007
LIABILITIES AND SHAREHOLDERS EQUITY		
Short-term debt	**$ 1,808**	$ 500
Long-term debt due within one year	**173**	18
Accounts payable	**939**	979
Accrued taxes	**177**	49
Accrued interest	**211**	160
Counterparty collateral	**9**	42
Customer deposits	**227**	219
Book overdrafts	**298**	212
Derivative liabilities	**175**	125
Regulatory liabilities	**1,179**	1,019
Other current liabilities	**931**	933
Total current liabilities	**6,127**	4,256
Long-term debt	**10,523**	9,016
Accumulated deferred income taxes net	**5,521**	5,196
Accumulated deferred investment tax credits	**185**	114
Customer advances	**134**	155
Derivative liabilities	**52**	101
Power-purchase contracts	**21**	22
Accumulated provision for pensions and benefits	**1,166**	1,089
Asset retirement obligations	**2,997**	2,892
Regulatory liabilities	**2,889**	3,433
Other deferred credits and other long-term liabilities	**1,544**	1,595
Total deferred credits and other liabilities	**14,509**	14,597
Total liabilities	**31,159**	27,869
Commitments and contingencies (Note 5)		
Minority interest	**319**	295
Preferred and preference stock of utility not subject to mandatory redemption	**907**	915
Common stock, no par value (325,811,206 shares outstanding at each date)	**2,263**	2,225
Accumulated other comprehensive income (loss)	**54**	(92)
Retained earnings	**6,964**	6,311
Total common shareholders equity	**9,281**	8,444
Total liabilities and shareholders equity	**$ 41,666**	$ 37,523

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Nine Months Ended September 30, 2008	2007
	(Unaudited)	
Cash flows from operating activities:		
Net income	**$ 999**	$ 887
Less: Income from discontinued operations		1
Income from continuing operations	**999**	886
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, decommissioning and amortization	**893**	937
Other-than-temporary impairment on nuclear decommissioning trusts	**121**	42
Other amortization	**80**	94
Stock-based compensation	**25**	28
Minority interest	**77**	134
Deferred income taxes and investment tax credits	**69**	(83)
Equity in income from partnerships and unconsolidated subsidiaries	**(40)**	(72)
(Gain) on buyout of contract and (gain)/loss on sale of assets	**(75)**	
Income from leveraged leases	**(39)**	(46)
Levelized rent expense	**(162)**	(161)
Loss on early extinguishment of debt		241
Regulatory assets	**(246)**	312
Regulatory liabilities	**122**	312
Derivative assets	**(60)**	3
Derivative liabilities	**86**	(105)
Other assets	**(71)**	(25)
Other liabilities	**(14)**	252
Margin and collateral deposits net of collateral received	**(70)**	28
Receivables and accrued unbilled revenue	**(378)**	(467)
Inventory and other current assets	**18**	(55)
Book overdrafts	**90**	113
Accrued interest and taxes	**179**	366
Accounts payable and other current liabilities	**(16)**	(46)
Distributions and dividends from unconsolidated entities	**9**	43
Operating cash flows from discontinued operations		1
Net cash provided by operating activities	**1,597**	2,732
Cash flows from financing activities:		
Long-term debt issued	**2,132**	2,930
Premium paid on extinguishment of debt and long-term debt issuance costs	**(15)**	(240)
Long-term debt repaid	**(246)**	(3,061)
Bonds repurchased	**(212)**	
Preferred stock redeemed	**(7)**	
Short-term debt financing-net	**1,308**	
Rate reduction notes repaid		(178)
Shares purchased for stock-based compensation	**(57)**	(195)
Proceeds from stock option exercises	**23**	77
Excess tax benefits related to stock-based awards	**12**	39
Dividends to minority shareholders	**(78)**	(76)
Dividends paid	**(298)**	(283)
Net cash provided (used) by financing activities	**$ 2,562**	$ (987)

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

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EDISON INTERNATIONAL

CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Nine Months Ended September 30, 2008	2007
	(Unaudited)	
Cash flows from investing activities:		
Capital expenditures	**$ (1,959)**	$ (1,979)
Purchase of interest of acquired companies	**(11)**	(28)
Proceeds from sale of property and interests in projects	**113**	
Proceeds from nuclear decommissioning trust sales	**2,279**	2,866
Purchases of nuclear decommissioning trust investments and other	**(2,329)**	(2,967)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment	**35**	17
Maturities and sales of short-term investments	**80**	7,380
Purchase of short-term investments	**(22)**	(7,174)
Restricted cash	**4**	35
Customer advances for construction and other investments	**(326)**	(232)
Net cash used by investing activities	**(2,136)**	(2,082)
Net increase (decrease) in cash and equivalents	**2,023**	(337)
Cash and equivalents, beginning of period	**1,441**	1,795
Cash and equivalents, end of period	**$ 3,464**	$ 1,458

The accompanying notes are an integral part of these consolidated 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 to fairly state the consolidated financial position, results of operations and cash flows in accordance with accounting principles generally accepted in the United States of America for the periods covered by this quarterly report on Form 10-Q. The results of operations for the three- and nine-month periods ended September 30, 2008 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 to Shareholders incorporated by reference into Edison International s Annual Report on Form 10-K for the year ended December 31, 2007 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 2007 Annual Report on Form 10-K. Edison International follows the same accounting policies for interim reporting purposes, with the exception of accounting principles adopted as of January 1, 2008 as discussed below in Margin and Collateral Deposits and New Accounting Pronouncements.

The December 31, 2007 condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America.

Certain prior-year reclassifications have been made to conform to the current year financial statement presentation mostly pertaining to the adoption of FIN No. 39-1. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

Cash Equivalents and Short-term Investments

At September 30, 2008, cash equivalents included U.S. treasury and government agency securities, U.S. treasury and government agency money market funds and commercial paper totaling $3.0 billion. At December 31, 2007, cash equivalents included money market funds, time deposits (including certificates of deposit) and U.S. treasury securities totaling $993 million. Cash equivalents, with the exception of money market funds, were stated at cost plus accrued interest. The carrying value of cash equivalents approximates fair value due to maturities of less than three months. For further discussion of money market funds, see Note 8.

At September 30, 2008 and December 31, 2007, Edison International classified all marketable debt securities as held-to-maturity. The securities were carried at amortized cost plus accrued interest which approximated their fair value. Gross unrealized holding gains and losses were not material.

Edison International s short-term investments consisted of the following:

In millions	**September 30, 2008** (Unaudited)	**December 31, 2007**
Commercial paper	**$ 1**	$ 32
Certificates of deposit		41
U.S. Treasury securities		7
Time deposits	**3**	

Money market funds		**19**		
Corporate bonds				1
Total	**$**	**23**	$	81

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Earnings Per Common Share

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 stock-based compensation awards payable in common shares, including stock options, performance shares and restricted stock units, which earn dividend equivalents on an equal basis with common shares. Stock options awarded during the period 2003 through 2006 received dividend equivalents. Stock options awarded prior to 2002 and after 2006 were granted without a dividend equivalent feature. As a result of meeting a performance trigger, the options granted in 1998 and 1999 began earning dividend equivalents in 2006. EPS was computed as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
In millions	2008	2007	2008	2007
		(Unaudited)		
Basic earnings per share continuing operations:				
Income from continuing operations	**$ 433**	$ 465	**$ 999**	$ 886
Gain on redemption of preferred stock			**2**	
Participating securities dividends	**(6)**	(6)	**(12)**	(10)
Income from continuing operations available to common shareholders	**$ 427**	$ 459	**$ 989**	$ 876
Weighted average common shares outstanding	**326**	326	**326**	326
Basic earnings per share continuing operations	**$ 1.31**	$ 1.41	**$ 3.03**	$ 2.69
Diluted earnings per share continuing operations:				
Income from continuing operations available to common shareholders	**$ 427**	$ 459	**$ 989**	$ 876
Income impact of assumed conversions	**3**	4	**6**	9
Income from continuing operations available to common shareholders and assumed conversions	**$ 430**	$ 463	**$ 995**	$ 885
Weighted average common shares outstanding	**326**	326	**326**	326
Incremental shares from assumed conversions	**2**	4	**3**	5
Adjusted weighted average shares diluted	**328**	330	**329**	331
Diluted earnings per share continuing operations	**$ 1.31**	$ 1.40	**$ 3.02**	$ 2.67

Stock-based compensation awards to purchase 3,874,740 and 37,057 shares of common stock for the three months ended September 30, 2008 and 2007, respectively, and 2,244,291 and 59,577 shares of common stock for the nine months ended September 30, 2008 and 2007, respectively, were outstanding, but were not included in the computation of diluted earnings per share because the exercise price of the awards was greater than the average market price of the common shares; therefore, the effect would have been antidilutive.

Intangible Assets

Other current assets on Edison International s consolidated balance sheets includes emission allowances purchased for use by EME of $65 million and $45 million at September, 2008 and December 31, 2007, respectively.

Other long-term assets on Edison International s consolidated balance sheets includes EME s project development rights, option rights, and purchased emission allowances and the total amounted to $74 million and $61 million, at September 30, 2008 and December 31, 2007, respectively.

Based on the CAIR requirements, Midwest Generation purchased annual NO_X allowances under the new CAIR annual NO_X program. Midwest Generation and EME Homer City continue to plan to meet the requirements of

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the CAIR as required under current law effective January 1, 2009. If the District of Columbia Circuit Court issues a mandate to vacate the CAIR, Midwest Generation would no longer need annual NO_X allowances and would record an impairment of $48 million at the time of such action.

Margin and Collateral Deposits

Margin and collateral deposits include margin requirements and cash deposited with and received from counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the related positions. See New Accounting Pronouncements below for a discussion of the adoption of FIN No. 39-1. In accordance with FIN No. 39-1, Edison International presents a portion of its margin and cash collateral deposits net with its derivative positions on its consolidated balance sheets. Amounts recognized for cash collateral provided to others that have been offset against net derivative liabilities totaled $98 million and $38 million at September 30, 2008 and December 31, 2007, respectively. Amounts recognized for cash collateral received from others that have been offset against net derivative assets totaled were less than $1 million at September 30, 2008.

New Accounting Pronouncements

Accounting Pronouncements Adopted

In April 2007, the FASB issued FIN No. 39-1. This pronouncement permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. In addition, upon the adoption, companies were permitted to change their accounting policy to offset or not offset fair value amounts recognized for derivative instruments under master netting agreements. Edison International adopted FIN No. 39-1 effective January 1, 2008. The adoption resulted in netting a portion of margin and cash collateral deposits with derivative positions on Edison International s consolidated balance sheets, but had no impact on its consolidated statements of income. The consolidated balance sheet at December 31, 2007 has been retroactively restated for the change, which resulted in a decrease in net assets (margin and collateral deposits) of $38 million. The consolidated statement of cash flows for the nine months ended September 30, 2007 has been retroactively restated to reflect the balance sheet changes, which had no impact on total operating cash flows from continuing operations.

In February 2007, the FASB issued SFAS No. 159, which provides an option to report eligible financial assets and liabilities at fair value, with changes in fair value recognized in earnings. Edison International adopted this pronouncement effective January 1, 2008. The adoption had no impact because Edison International did not make an optional election to report additional financial assets and liabilities at fair value.

In September 2006, the FASB issued SFAS No. 157, which clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. Edison International adopted SFAS No. 157 effective January 1, 2008. The adoption did not result in any retrospective adjustments to its consolidated financial statements. The accounting requirements for employers pension and other postretirement benefit plans are effective at the end of 2008, which is the next measurement date for these benefit plans. The effective date will be January 1, 2009 for asset retirement obligations and other nonfinancial assets and liabilities which are measured or disclosed on a non-recurring basis. For further discussion, see Note 8.

On October 10, 2008, the FASB issued FSP SFAS No. 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active. This position clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. It also reaffirms the notion of fair value as an exit price as of the measurement date. This position was effective upon issuance, including prior periods for which financial statements have not been issued. The adoption had no impact on Edison International s consolidated financial statements.

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Accounting Pronouncements Not Yet Adopted

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

In December 2007, the FASB issued SFAS No. 160, which requires an entity to present minority interest that reflects the ownership interests in subsidiaries held by parties other than the entity, within the equity section but separate from the entity s equity in the consolidated financial statements. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interest be accounted for similarly as equity transactions; and, when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary be measured at fair value. Edison International will adopt SFAS No. 160 on January 1, 2009. In accordance with this standard, Edison International will reclassify minority interest to a component of shareholders equity (at September 30, 2008 this amount was $319 million).

In March 2008, the FASB issued SFAS No. 161, which requires additional disclosures related to derivative instruments, including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008, with early adoption permitted. Edison International will adopt SFAS No. 161 in the first quarter of 2009. SFAS No. 161 will impact disclosures only and will not have an impact on Edison International s consolidated results of operations, financial condition or cash flows.

In April 2008, the FASB issued FSP FAS No. 142-3 which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, Goodwill and Other Intangible Assets. The intent of the position is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141(R) and other U.S. generally accepted accounting principles. Edison International will adopt FSP FAS No. 142-3 on January 1, 2009. Edison International is currently evaluating the impact, if any, that the adoption of this position could have on its consolidated financial statements.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements for nongovernmental entities that are presented in conformity with U.S. GAAP. This statement transfers the GAAP hierarchy from the American Institute of Certified Public Accountants Statement on Auditing Standards No. 69, The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles to the FASB. SFAS No. 162 is effective on November 15, 2008. Edison International expects that the adoption of this standard will not have an impact on Edison International s consolidated results of operations, financial condition or cash flows.

In September 2008, the FASB issued FSP SFAS No. 133-1 and FIN No. 45-4. FSP SFAS No. 133-1 requires enhanced disclosures by sellers of credit derivatives and amends FASB Interpretation No. 45 (FIN No. 45), Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, to require additional disclosure about the current status of the payment/performance risk of a guarantee. The provisions of the FSP that amend SFAS No. 133 and FIN No. 45 are effective for reporting

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periods ending after November 15, 2008. Since FSP FAS No. 133-1 and FIN No. 45-4 only require additional disclosures, the adoption will not impact Edison International s consolidated financial position, results of operations or cash flows.

Property and Plant

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and AFUDC. AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. Currently, AFUDC debt and equity is capitalized during certain plant construction and reported in interest expense and other nonoperating income, respectively. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset.

On November 26, 2007, the FERC issued an order granting incentives on three of SCE s largest proposed transmission projects, DPV2, Tehachapi Transmission Project (Tehachapi), and Rancho Vista Substation Project (Rancho Vista). The order permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction of all three projects. On February 29, 2008, the FERC approved SCE s revision to its Transmission Owner Tariff to collect 100% of construction work in progress (CWIP) for these projects in rate base and earn a return on equity, rather than capitalizing AFUDC. SCE implemented the CWIP rate, subject to refund, on March 1, 2008. For further discussion, see FERC Transmission Incentives in Note 5.

Related Party Transactions

During the first quarter of 2008, a subsidiary of EME was awarded through a competitive bidding process a ten-year power sales contract with SCE for the output of a 479 MW gas-peaking facility located in the City of Industry, California, which is referred to as the Walnut Creek project. The power sales agreement was approved by the CPUC on September 18, 2008 and by the FERC on October 2, 2008. Deliveries under the power sales agreement are expected to commence in 2013.

Note 2. Liabilities and Lines of Credit

Long-Term Debt

In January 2008, SCE issued $600 million of 5.95% first and refunding mortgage bonds due in 2038. The proceeds were used to repay SCE s outstanding commercial paper of approximately $426 million and for general corporate purposes. In August 2008, SCE issued $400 million of 5.50% first and refunding mortgage bonds due in 2018. The proceeds were used to repay SCE s outstanding commercial paper of approximately $110 million and borrowings under the credit facility of $200 million, as well as for general corporate purposes. In October 2008, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014. The proceeds were used for general corporate purposes.

The interest rates on one issue of SCE s pollution control bonds insured by FGIC, totaling $249 million, were reset every 35 days through an auction process. Due to a loss of confidence in the creditworthiness of

the bond insurers, there was a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds increased. Consequently, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and the remaining $212 million during the first three months of 2008. In March 2008, SCE converted the issue to a variable rate mode and terminated the FGIC insurance policy. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.

EME and its subsidiary, Midwest Generation, made borrowings under their credit agreements totaling $898 million to enhance liquidity. Proceeds from these borrowings were invested in U.S. treasury securities, U.S. government agency securities, and money market funds invested directly in U.S. treasury securities and U.S. government agency securities.

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Short-Term Debt

SCE s short-term debt is generally used to finance fuel inventories, balancing account undercollections and general, temporary cash requirements including power-purchase payments. At September 30, 2008, the outstanding short-term debt was $1.56 billion at a weighted-average interest rate of 3.53%. This short-term debt is supported by a $2.5 billion credit line. See below in Credit Agreements.

EIX short-term debt is generally used for liquidity purposes. At September 30, 2008, the outstanding short-term debt was $250 million at a weighted-average interest rate of 3.39%. This short-term debt is supported by a $1.5 billion credit line. See below in Credit Agreements.

Credit Agreements

During the third quarter of 2008, Edison International (parent) and its subsidiaries, made borrowings under their respective credit agreements. The following table summarizes the status of these credit facilities at September 30, 2008:

In millions	**SCE**	**EMG**	**Edison International (parent)**
		(Unaudited)	
Commitment	$ 2,500	$ 1,100	$ 1,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(81)	(36)	(62)
	2,419	1,064	1,438
Outstanding borrowings	(1,558)	(898)	(250)
Outstanding letters of credit	(233)	(121)	
Amount available	$ 628	$ 45	$ 1,188

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB is one of the lenders in SCE s and Edison International (parent) credit agreement representing a total commitment of $106 million and $74 million, respectively. In September 2008, Lehman Brothers Bank, FSB declined SCE s request for funding of the most recent borrowings, or approximately $42 million. This subsidiary fully funded $12 million of Edison International (parent) borrowing request, which remains outstanding.

A subsidiary of Lehman Brothers Holdings, Lehman Commercial Paper Inc., is one of the lenders in EME s credit agreement representing a commitment of $36 million. In September 2008, Lehman Commercial Paper declined requests for funding under EME s credit agreement. Another subsidiary of Lehman Brothers Holdings, Lehman Brothers Commercial Bank, Inc., is one of the lenders in the Midwest Generation working capital facility. This subsidiary fully funded $42 million of Midwest Generation s borrowing requests, which remains outstanding. At September 30, 2008, Lehman Brothers Commercial Bank s share of the amount available to draw under the Midwest Generation working capital facility was $2 million.

Note 3. Income Taxes

Edison International s composite federal and state statutory income tax rate was approximately 40% (net of federal benefit for state income taxes) for all periods presented. Edison International s effective tax rate was 39% and 34% for the three- and nine-month periods ended September 30, 2008, as compared to 36% and 31% for the respective periods in 2007. The higher effective income tax rate for the three months ended September 30, 2008 as compared to the respective period in 2007, was primarily due to two SCE non-deductible expenses recorded in 2008, consisting of a penalty assessed by the CPUC (see Investigation Regarding Performance Incentives Rewards in Note 5) and higher lobbying expenses. The higher effective tax rates for the nine months ended September 30, 2008 as compared to the respective period in 2007, were due to both previously-mentioned non-deductible expenses and reductions in SCE s income tax reserve recorded in the first quarter of 2007 to reflect progress made in an administrative appeal process with the IRS related to the income tax treatment of certain costs associated with environmental remediation and to reflect a settlement of state tax audit issues. The previously mentioned factors causing an increase to the 2008 federal and state effective tax rates as compared to 2007 were partially offset by higher SCE software and property-related flow-through deductions recorded in 2008.

Accounting for Uncertainty in Income Taxes

FIN 48 requires an enterprise to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. Edison International has filed affirmative tax claims related to tax positions, which, if accepted, could result in refunds of taxes paid or additional tax benefits for positions not reflected on filed original tax returns. FIN 48 requires the disclosure of all unrecognized tax benefits, which includes the reserves recorded for tax positions on filed tax returns and the unrecognized portion of affirmative claims.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits from January 1, 2008 to September 30, 2008 and the reasons for such changes:

In millions	(Unaudited)
Balance at January 1, 2008	$ 2,114
Tax positions taken during the current year	
Increases	75
Decreases	
Tax positions taken during a prior year	
Increases	105
Decreases	(129)
Decreases for settlements during the period	
Reductions for lapses of applicable statute of limitations	
Balance at September 30, 2008	**$ 2,165**

The unrecognized tax benefits in the table above reflect affirmative claims related to timing differences of $1.5 billion and $1.6 billion at September 30, 2008 and January 1, 2008, respectively, but have not met the recognition threshold pursuant to FIN 48 and have been denied by the IRS as part of their examinations. These affirmative claims remain unpaid by the IRS and no receivable has been recorded. Edison International has vigorously defended these affirmative claims in IRS administrative appeals proceedings and these claims are included in the ongoing Global Settlement negotiations.

It is reasonably possible that Edison International could resolve, as part of the Global Settlement, or otherwise, with the IRS, all or a portion of the unrecognized tax benefits through tax year 2002 within the next 12 months, which could reduce unrecognized tax benefits by up to $1.4 billion.

The total amount of unrecognized tax benefits as of September 30, 2008 and January 1, 2008 that, if recognized, would have an effective tax rate impact is $207 million and $206 million, respectively.

Accrued Interest and Penalties

The total amounts of accrued interest and penalties related to Edison International s income tax reserve were $193 million and $162 million as of September 30, 2008 and January 1, 2008, respectively. The after-tax interest expense recognized and included in income tax expense was $5 million and $18 million for the three- and nine-month periods ended September 30, 2008, respectively.

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Tax Positions being Addressed as Part of Active Examinations, Administrative Appeals and the Global Settlement

Edison International is challenging certain IRS deficiency adjustments for tax years 1994 1999 with the Administrative Appeals branch of the IRS and Edison International is currently under active IRS examination for tax years 2000 2006. During the third quarter of 2008, the IRS commenced an examination of tax years 2003 2006. In addition, the statute of limitations remains open for tax years 1986 1993, which has allowed Edison International to file certain affirmative claims related to these tax years. Tax years 1986 2002 are included in the scope of the Global Settlement and tax years 2003 2006 are excluded, except for the cross-border lease issues, which for these later tax years are included in the scope of the Global Settlement.

Most of these tax positions relate to timing differences and, therefore, any amounts exclusive of any penalties that would be paid if Edison International s position is not sustained would be deductible on future tax returns filed by Edison International. In addition, Edison International has filed affirmative claims with respect to certain tax years 1986 through 2005 with the IRS and state tax authorities. Any benefits associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when Edison International would make an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement of the affirmative claim is consummated with the tax authority. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

Currently, Edison International is under administrative appeals with the California Franchise Tax Board for tax years 1997 2002 and under examination for tax years 2003 2004. Edison International remains subject to examination by the California Franchise Tax Board for tax years 2005 and forward. Edison International is also subject to examination by other state tax authorities, subject to varying statute of limitations.

Edison International filed amended California Franchise tax returns for tax years 1997 2002 to mitigate the possible imposition of California non-economic substance 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 below. Edison International filed these amended returns under protest retaining its appeal rights.

Balancing Account Over-Collections

In response to an affirmative claim filed by Edison International related to balancing account over-collections, the IRS issued a Notice of Proposed Adjustment in July 2007. This affirmative claim was addressed by the IRS as part of the ongoing IRS examinations and administrative appeals processes. The tax years to which adjustments are made pursuant to this Notice of Proposed Adjustment are included in the scope of the Global Settlement. The cash and earnings impacts of this position are dependent on the ultimate settlement of all open tax issues, including this issue, in these tax years. Edison International expects that resolution of this issue could potentially increase earnings and cash flows within the range of $70 million to $80 million and $300 million to $350 million, respectively.

Contingent Liability Company

The IRS has asserted deficiencies with respect to a transaction entered into by a former SCE subsidiary which may be considered substantially similar to a Listed Transaction described by the IRS as a contingent liability company for tax years 1997 and 1998. This issue is included in the Global Settlement and is being considered by the Administrative Appeals branch of the IRS where Edison International has been defending its income tax return position with respect to this transaction.

Cross-Border Lease Transactions

As part of a nationwide challenge of cross-border lease transactions, the IRS has asserted deficiencies related to Edison International s deferral of income taxes associated with certain of its cross-border, leveraged leases.

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These asserted deficiencies relate to Edison Capital s income tax treatment of both its foreign power plant and electric locomotive sale/leaseback transactions entered into in 1993 and 1994 (Replacement Leases, which the IRS refers to as sale-in/lease-out or SILOs) and its foreign power plants and electric transmission system lease/ leaseback transactions entered into in 1997 and 1998 (Lease/Leaseback, which the IRS refers to as lease-in/ lease-out or LILOs). For tax years 1994 1999, Edison International is challenging the asserted deficiencies in ongoing IRS appeals proceedings and as part of the Global Settlement.

In 1999, Edison Capital entered into a lease/service contract transaction involving a foreign telecommunication system (Service Contract, which the IRS refers to as a SILO). As part of an ongoing examination of 2000 2002, the IRS examination branch has been reviewing Edison International s income tax treatment of this Service Contract. The income tax treatment of the Service Contract is included in the Global Settlement for all tax years. The following table summarizes estimated federal and state income taxes deferred from these leases as of December 31, 2007. Repayment of the entire amount of the deferred income taxes, as provided in the table below, would be accelerated if Edison International and the IRS are unable to reach a settlement and the IRS position is to be sustained in litigation:

	Tax Years Under Appeal	**Tax Years Under Audit**	**Unaudited Tax Years**	
In millions	**1994 1999**	**2000 2006**	**2007**	**Total**
Replacement Leases (SILO)	$ 44	$ 42	$ 4	$ 90
Lease/Leaseback (LILO)	563	572	(14)	1,121
Service Contract (SILO)		326	54	380
Total	$607	$940	$ 44	$1,591

As of September 30, 2008, the after-tax interest on the proposed tax adjustments is estimated to be approximately $613 million. The IRS has also asserted a 20% penalty on any sustained adjustment (other than with respect to the Service Contract).

Edison International believes that its maximum earnings exposure related to these leases, measured as of September 30, 2008, is approximately $1.3 billion after taxes, calculated by reclassifying deferred income taxes to current, re-computing the cumulative earnings under the leases in accordance with lease accounting rules (FASB Staff Position FAS 13-2), and recording interest related to the current income tax liability. Interest will continue to accrue until settled. This exposure does not include IRS asserted penalties of 20%, as Edison International does not believe that even if the tax benefits taken by Edison Capital are successfully challenged by the IRS that these penalties would be sustained. The current and future earnings and cash positions of SCE and EME are virtually unaffected by these leases.

During the second quarter of 2008, there were court decisions involving income taxation of cross-border leveraged leases that were adverse to the taxpayers involved. These developments underscore the uncertain nature of tax conclusions in this area. Despite these developments, Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law and, in the absence of any settlement with the IRS, will continue to vigorously defend its tax treatment of these leases. Edison International will continue to monitor and evaluate its lease transactions with respect to future events. Future adverse developments, including further adverse case law developments, could change Edison International s current conclusions.

As previously disclosed, Edison International is currently engaged in settlement negotiations with the IRS to reach a Global Settlement which, if consummated, would resolve cross-border, leveraged lease issues in their entirety and all other outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. These negotiations have progressed to the point where Edison International and the IRS have reached nonbinding, preliminary understandings on the material principles for resolving the lease issues as part of the resolution of all issues included in the Global Settlement. Final resolution of such disputes, as part of the Global Settlement, is subject to reaching definitive agreements on final terms and calculations, mutually satisfactory documentation, and review of all or a portion of the Global Settlement by the

Staff of the Joint Committee on Taxation, a committee of the United States Congress (the Joint Committee). While not assured, Edison International believes that the Global Settlement will be submitted or substantially ready to be submitted to the Joint Committee during the fourth quarter of 2008.

Edison International expects that the leases will be terminated in anticipation of the Global Settlement. Timing of termination is uncertain and could occur prior to the Joint Committee completing its work or otherwise prior to consummation of the settlement. Edison Capital and its subsidiaries have either reached agreement or are negotiating agreements based on executed term sheets with all of the counterparties to its SILOs and LILOs which contemplate termination of the leases subject to a final settlement agreement with the IRS. Certain of these agreements will not be binding on Edison Capital or the counterparties until such termination. Upon termination of the leases, the lessees would be required to make termination payments from certain collateral deposits associated with the leases, and Edison International would no longer recognize earnings from such leases.

If all settlements included in the Global Settlement discussions were ultimately concluded consistent with the preliminary understandings, Edison International would expect that the settlement of the disputed lease issues and the resolution of the above-mentioned affirmative claims would result in a portion of the charge initially recorded upon termination of the leases being offset and/or reduced, and the net after-tax earnings charge that would remain is currently expected to be less than half of the maximum after-tax earnings exposure, calculated as of September 30, 2008, discussed above. Accordingly, it is not anticipated that borrowings would be required in connection with implementation of the settlements. Termination of the leases prior to consummation of the settlements would result in Edison International initially recording an after-tax charge to earnings currently estimated to be at least $650 million (and potentially up to the maximum earnings exposure indicated above), which would be reduced and/or offset upon completion of the settlements.

There can be no assurance, however, about the timing of final settlements with the IRS or that such final settlements will be ultimately consummated. Moreover, review by the Joint Committee could result in adjustments to the Global Settlement reached between Edison International and the IRS. The IRS and Edison International may not reach final agreements that implement the preliminary understandings, or they may reach final agreements but conditions to consummating them may not be satisfied. If Edison International terminated the SILO and LILO leases without consummating the Global Settlement or any other settlement with the IRS, of the cross-border lease issues, then it could not seek through litigation with the IRS future deferred tax benefits that may have been otherwise available in the absence of termination.

To the extent that an acceptable settlement is not reached with the IRS, Edison International will continue to vigorously defend its tax treatment of the leases and is prepared to take legal action. If Edison International were to commence litigation in certain forums, it would need to make payments of the disputed taxes, along with interest and any penalties asserted by the IRS, and thereafter pursue refunds. In the United States Tax Court, the other litigation forum, no upfront payment would be required. In 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 IRS did not act on this refund claim within the statutory six month period, which provides Edison International with the option of being able to take legal action to assert its refund claim. To the extent an acceptable settlement is not reached with the IRS, Edison International, based on its preference for litigation forum, may file refund claims for any taxes, interest and penalties paid for tax years related to these leases. However, Edison International has not decided whether and to what extent it would make additional payments related to later tax years to fund its right to litigate in certain forums should the Global Settlement, or another settlement, not be consummated.

Resolution of Federal and State Income Tax Issues Being Addressed in Ongoing Examinations, Administrative Appeals and the Global Settlement

Edison International continues its efforts to resolve open tax issues through tax year 2002 as part of the Global Settlement. Although the timing for resolving these open tax positions is uncertain, it is reasonably possible that all or a significant portion of these open tax issues through tax year 2002 could be resolved within the next 12 months.

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Note 4. Compensation and Benefits Plans

Pension Plans

As of September 30, 2008, Edison International had made $16 million in contributions related to 2007 and $45 million related to 2008 and estimates to make $14 million of additional contributions in the last three months of 2008.

Volatile market conditions have affected the value of Edison International s trusts established to fund its future long-term pension benefits. The market value of the investments within the plan trusts declined 22% during the nine months ended September 30, 2008. These benefit plan assets and related obligations are remeasured annually using a December 31 measurement date. Unless the market recovers, reductions in the value of plan assets will result in increased future expense, a change in the pension plan funding status from overfunded to underfunded and increased future contributions. Changes in the plan s funded status will affect the assets and liabilities recorded on the balance sheet in accordance with SFAS No. 158. Due to SCE s regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts. The Pension Protection Act of 2006 establishes new minimum funding standards and prohibits plans underfunded by more than 20% from providing lump sum distributions and adopting amendments that increase plan liabilities.

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.

Expense components are:

In millions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
		(Unaudited)		
Service cost	**$ 32**	$ 31	**$ 95**	$ 93
Interest cost	**50**	47	**151**	141
Expected return on plan assets	**(65)**	(63)	**(197)**	(190)
Amortization of prior service cost	**4**	4	**13**	12
Amortization of net loss		1	**1**	4
Expense under accounting standards	**21**	20	**63**	60
Regulatory adjustment deferred		1		3
Total expense recognized	**$ 21**	$ 21	**$ 63**	$ 63

Postretirement Benefits Other Than Pensions

As of September 30, 2008, Edison International had made no contributions related to 2007 and $14 million related to 2008 and estimates to make $26 million of additional contributions in the last three months of 2008.

Volatile market conditions have affected the value of Edison International s trust established to fund its future other postretirement benefits. The market value of the investments within the plan trust declined 21% during the nine months ended September 30, 2008. These benefit plan assets and related obligations are remeasured annually using a December 31 measurement date. Unless the market recovers, reductions in the value of plan assets will result in increased future expense, an increase in the plan underfunded status and increased future contributions. Changes in the plan s funded status will affect the assets and liabilities recorded on the balance sheet in accordance with SFAS No. 158. Due to SCE s regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to this trust.

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Expense components are:

In millions	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
	(Unaudited)			
Service cost	**$ 12**	$ 11	**$ 36**	$ 33
Interest cost	**35**	32	**105**	96
Expected return on plan assets	**(31)**	(30)	**(93)**	(90)
Amortization of prior service credit	**(8)**	(8)	**(24)**	(24)
Amortization of net loss	**4**	7	**12**	21
Total expense recognized	**$ 12**	$ 12	**$ 36**	$ 36

Stock-Based Compensation

During the first quarter of 2008, Edison International granted its 2008 stock-based compensation awards, which included stock options, performance shares, deferred stock units and restricted stock units. Total stock-based compensation expense (reflected in the caption Other operation and maintenance on the consolidated statements of income) was $5 million and $9 million for the three months ended September 30, 2008 and 2007, respectively, and was $24 million and $38 million for the nine months ended September 30, 2008 and 2007, respectively. The income tax benefit recognized in the consolidated statements of income was $2 million and $4 million for the three months ended September 30, 2008 and 2007, respectively, and was $10 million and $15 million for the nine months ended September 30, 2008 and 2007, respectively. Total stock-based compensation cost capitalized was less than $1 million and $1 million for the three months ended September 30, 2008 and 2007, respectively, and was $2 million and $4 million for the nine months ended September 30, 2008 and 2007, respectively.

Stock Options

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

	Stock Options	Weighted-Average Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
	(Unaudited)			
Outstanding at December 31, 2007	12,105,642	$ 30.55		
Granted	2,814,119	$ 48.61		
Expired	(500)	$ 28.94		
Forfeited	(324,913)	$ 49.28		
Exercised	(881,690)	$ 25.82		
Outstanding at September 30, 2008	13,712,658	$ 34.12	6.48	
Vested and expected to vest at September 30, 2008	13,261,884	$ 33.71	6.41	$ 168,160,689
Exercisable at September 30, 2008	8,214,131	$ 26.60	5.27	$ 162,557,652

Stock options granted in 2008 do not accrue dividend equivalents.

The amount of cash used to settle stock options exercised was $5 million and $12 million for the three months ended September 30, 2008 and 2007, respectively, and was $46 million and $174 million for the nine months ended September 30, 2008 and 2007, respectively. Cash received from options exercised was $3 million and

$5 million for the three months ended September 30, 2008 and 2007, respectively, and was $23 million and $77 million for the nine months ended September 30, 2008 and 2007, respectively. The estimated tax benefit from options exercised was $1 million and $3 million for the three months ended September 30, 2008 and 2007, respectively, and was $9 million and $39 million for the nine months ended September 30, 2008 and 2007, respectively.

Note 5. Commitments and Contingencies

The following is an update to Edison International s commitments and contingencies. See Note 6 of Notes to Consolidated Financial Statements included in Edison International s 2007 Annual Report on Form 10-K for a detailed discussion.

Lease Commitments

During the second quarter of 2008, SCE entered into power-purchase contracts which are classified as operating leases. The contract terms range from 10 to 20 years. The delivery of energy under one of these contracts is not expected to commence until 2018. These additional commitments are currently estimated to be: remainder of 2008 $4 million, 2009 $14 million, 2010 $15 million, 2011 $15 million, 2012 $15 million and thereafter $828 million.

During the third quarter of 2008, SCE entered into power-purchase contracts which are classified as capital leases. The contract terms are 20 years. The delivery of energy under these contracts is expected to commence in 2010. These additional commitments are currently estimated to be: 2010 $32 million, 2011 $119 million, 2012 $119 million and thereafter $2.6 billion. The estimated executory costs and interest expense associated with these additional commitments are $699 million and $988 million, respectively. The total additional estimated net commitments are $1.2 billion.

Other Commitments

During the first nine months of 2008, SCE entered into service contracts associated with uranium enrichment and fuel fabrication. As a result, SCE s additional fuel supply commitments are estimated to be: 2009 $51 million, 2010 $54 million, 2011 $98 million, 2012 $146 million and thereafter $671 million.

During the second quarter of 2008, SCE entered into a new power-purchase contract. The delivery of energy under this contract is expected to commence in August 2010 with a 10 year term. SCE s additional commitments upon commencement are estimated to be: 2010 $188 million, 2011 $335 million, 2012 $341 million and thereafter $2.7 billion.

At September 30, 2008, EME s subsidiaries had firm commitments to spend approximately $204 million during the remainder of 2008 and $42 million in 2009 on capital and construction expenditures. The majority of these expenditures relate to the construction of wind projects. These expenditures are planned to be financed by cash on hand and cash generated from operations.

EME had entered into various turbine supply agreements with vendors to support its wind and thermal development efforts. At September 30, 2008, EME had secured 484 wind turbines (942 MW) and 5 gas-fired turbines (479 MW) for use in future projects for an aggregate purchase price of $1.4 billion, with remaining commitments of $66 million in 2008, $794 million in 2009 and $260 million in 2010. At September 30, 2008, EME had recorded wind turbine deposits of $318 million included in other long-term assets on its consolidated balance sheet.

In connection with the acquisition of the Illinois Plants, Midwest Generation had assumed a long-term coal supply contract and recorded a liability to reflect the fair value of this contract. In March 2008, Midwest Generation entered into an agreement to buy-out its coal obligations for the years 2009 through 2012 under this

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contract with a one-time payment to be made in January 2009. Midwest Generation recorded a pre-tax gain of $15 million ($9 million, after tax) during the first quarter of 2008 reflected in (Gain) on buyout of contract and (gain)/loss on sale of assets on the consolidated statements of income. The remaining payments due under this contract are $15 million.

EME s subsidiaries had entered into contractual agreements during the first nine months of 2008 to purchase materials for environmental controls equipment. In addition, during the nine months ended September 30, 2008, EME s subsidiaries entered into turbine operations and maintenance agreements. These commitments are currently estimated to aggregate to $196 million, summarized as follows: remainder of 2008 $3 million, 2009 $31 million, 2010 $48 million, 2011 $48 million, 2012 $46 million, and thereafter $20 million.

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.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions related to the Homer City facilities in Pennsylvania, the Powerton and Joliet Stations in Illinois and, previously, the Collins Station in Illinois, EME and several of its subsidiaries entered into tax indemnity agreements. Although the Collins Station lease terminated in April 2004, Midwest Generation s tax indemnity agreement with the former lease equity investor is still in effect. 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.

Indemnities Provided as Part of the Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois Plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison takes all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV discussed below under Contingencies Midwest Generation New Source Review Notice of Violation. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. 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 LLC on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Asset Sale Agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest

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Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2009. Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were approximately 208 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at September 30, 2008. Midwest Generation had recorded a $53 million liability at September 30, 2008 related to this matter.

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

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

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

Indemnities Provided under Asset Sale Agreements

The asset sale agreements for the sale of EME s international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At September 30, 2008, EME had recorded a liability of $97 million related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At September 30, 2008, EME had recorded a liability of $13 million related to these matters.

Capacity Indemnification Agreements

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project s power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power sales agreements. The obligations under this indemnification agreement as of September 30, 2008, if payment were required, would be $63 million. EME has not recorded a liability related to this indemnity.

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. 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.

Mountainview Filter Cake Indemnity

Mountainview owns and operates a power plant in Redlands, California. The plant utilizes water from on-site groundwater wells and City of Redlands (City) recycled water for cooling purposes. Unrelated to the operation of the plant, this water contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant s wastewater treatment filter cake. Use of this impacted groundwater for cooling purposes was mandated by Mountainview s CEC permit. Mountainview has indemnified the City for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City s solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this guarantee.

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 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.

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 consolidated results of operations or liquidity.

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 consolidated financial position and results of operations would not be materially affected.

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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.

As of September 30, 2008, Edison International s recorded estimated minimum liability to remediate its 45 identified sites at SCE (24 sites) and EME (21 sites primarily related to Midwest Generation) was $50 million, $47 million of which was related to SCE including $14 million related to San Onofre. This remediation liability is undiscounted. 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 $167 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 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $32 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 $42 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.

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 $31 million. Recorded costs for the 12 months ended September 30, 2008 were $32 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 consolidated 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

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 certain lease and kind of lease transactions. See Note 3 for further details.

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FERC Transmission Incentives

On November 16, 2007, the FERC issued an order granting incentives on three of SCE s largest proposed transmission projects:

A 125 basis point ROE adder on SCE s future proposed base ROE (ROE Adder) for DPV2, which is a high voltage (500 kV) transmission line from the Valley substation to the Devers substation near Palm Springs, California to a new substation near Palo Verde, west of Phoenix, Arizona;

A 125 basis point ROE Adder for the Tehachapi Transmission Project, which is an eleven segment project consisting of newly-constructed and upgraded transmission lines and associated substations to interconnect renewable generation projects near the Tehachapi and Big Creek area; and

A 75 basis point ROE Adder for the Rancho Vista Substation Project, which is a new 500 kV substation in the City of Rancho Cucamonga. The order also grants a higher return on equity on SCE s entire transmission rate base in SCE s next FERC transmission rate case for SCE s participation in the CAISO. In September 2008, the FERC accepted SCE s revisions to its Transmission Owner Tariff, with a requested effective date of March 1, 2009 subject to refund and settlement procedures. In addition, the order permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction, also known as CWIP, of all three projects and 100% recovery of prudently-incurred abandoned plant costs for DPV2 and Tehachapi, if either or both of these projects are cancelled due to factors beyond SCE s control.

In June 2008, the FERC rejected petitions filed by certain parties, including the CPUC, to address the CAISO higher return and the ROE project adders. In August 2008, the CPUC filed an appeal of the FERC incentives order at the DC Circuit Court of Appeals.

FERC Construction Work in Progress Mechanism

On December 21, 2007, SCE filed a revision to its Transmission Owner Tariff to collect 100% of CWIP in rate base for its Tehachapi, DPV2, and Rancho Vista projects. In the CWIP filing, SCE proposed a rate adjustment ($45 million or a 14.4% increase) to SCE s currently authorized base transmission revenue requirement to be made effective on March 1, 2008 and later adjusted for amounts actually spent in 2008 through a new balancing account mechanism. The rate adjustment represents actual expenditures from September 1, 2005 through November 30, 2007, projected expenditures from December 1, 2007 through December 31, 2008, and a ROE (which includes the ROE adders approved for Tehachapi, DPV2 and Rancho Vista). The rate adjustment is based on a projection that SCE will spend a total of approximately $244 million, $27 million, and $181 million for Tehachapi, DPV2, and Rancho Vista, respectively, from September 1, 2005 through the end of 2008. The 2008 DPV2 expenditure forecast is limited to projected consulting and legal costs associated with SCE s continued efforts to obtain regulatory approvals necessary to construct the DPV2 Project. On February 29, 2008, the CWIP filing was approved and SCE implemented the CWIP rate on March 1, 2008, subject to refund on the limited issue of whether SCE s proposed ROEs are reasonable. On March 28, 2008, the CPUC filed a petition for rehearing with the FERC on the FERC s acceptance of SCE s proposed ROE for CWIP. Briefs addressing the appropriate ROE were filed by SCE and intervenors in May 2008. In addition, in the order, SCE was directed by FERC to make a compliance filing to provide greater detail on the costs reflected in CWIP rates for 2008. SCE made the compliance filing on March 31, 2008. On April 21, 2008, the CPUC filed a protest of the compliance filing at FERC and requested an evidentiary hearing to be set to further review the costs. SCE filed a response to the CPUC s protest on May 6, 2008 arguing that the FERC should deny the CPUC s request for a further hearing. SCE cannot predict the outcome of the matters in this proceeding.

SCE filed its 2009 update to its CWIP rate adjustment on October 31, 2008. SCE proposed a reduction to its CWIP revenue requirement from $45 million to $39 million to be effective on January 1, 2009.

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Investigation Regarding Performance Incentives Rewards

SCE was eligible under the CPUC-approved PBR mechanism to earn rewards or incur penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee safety reporting, and system reliability. SCE conducted investigations into its performance under the PBR mechanism and reported to the CPUC certain findings of misconduct and misreporting related to the first two components of the PBR program. Following SCE s reporting, the CPUC opened its own investigation of SCE s activities relative to the PBR mechanism.

CPUC Decision

On September 18, 2008, the CPUC adopted a decision in the first phase of its investigation into SCE s incentives claimed under the CPUC-approved PBR mechanism that allowed SCE to earn rewards or incur penalties for the period 1997 2003 based on its performance in comparison to CPUC-approved standards of customer satisfaction and employee safety reporting. The adopted decision required SCE to refund $28 million and $20 million related to customer satisfaction and employee safety reporting incentives, respectively; and further required SCE to forego claimed incentives of $20 million and $15 million related to customer satisfaction and employee safety reporting, respectively. The decision also required SCE to refund $33 million for employee bonuses and imposed a statutory penalty of $30 million. During the third quarter, SCE recorded a charge of $49 million, after-tax, reflected primarily in Other nonoperating deductions in the consolidated statements of income related to this decision.

System Reliability

In light of the problems uncovered with the components of the PBR mechanism discussed above, SCE conducted an investigation into the third PBR standard, system reliability, for the years 1997 2003. SCE received $8 million in reliability incentive awards for the period 1997 2000 and had applied for a reward of $5 million for 2001. For 2002, SCE s data indicated that it earned no reward and incurred no penalty. For 2003, based on the application of the PBR mechanism, SCE determined that it would incur a penalty of $3 million and accrued a charge for that amount in 2004. On February 28, 2005, SCE provided its final investigation report to the CPUC concluding that the reliability reporting system was working as intended. System reliability incentives will be addressed in the second phase of the CPUC s investigation. SCE served its opening testimony in the second phase in September 2007. In that testimony, SCE presented evidence that its PBR system reliability results were valid. The schedule for the second phase of the investigation has been deferred until November 21, 2008. SCE cannot predict the outcome of the second phase but does not expect a material financial statement impact.

EME Homer City New Source Review Notice of Violation

On June 12, 2008, EME Homer City received an NOV from the US EPA alleging that, beginning in 1988, EME Homer City (or former owners of the Homer City facilities) performed repair or replacement projects at Homer City Units 1 and 2 without first obtaining construction permits as required by the Prevention of Significant Deterioration requirements of the Clean Air Act. The US EPA also alleges that EME Homer City has failed to file timely and complete Title V permits. EME Homer City has met with the US EPA and has expressed its intent to explore the possibility of a settlement. If no settlement is reached and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. EME Homer City is investigating the NOV claims and is developing a litigation strategy. EME Homer City cannot predict at this time what effect this matter may have on its facilities, its results of operations, financial position or cash flows. EME Homer City has sought indemnification for liability and defense costs associated with the NOV from the sellers under the asset purchase agreement pursuant to which EME Homer City acquired the Homer City facilities. The sellers responded by denying the indemnity obligation, but accepting the defense of the claims.

EME Homer City notified the sale-leaseback owner participants of the Homer City facilities of the NOV under the operative indemnity provisions of the sale-leaseback documents. The owner participants of the Homer City facilities, in turn, have sought indemnification and defense from EME Homer City for costs and liability associated with the EME Homer City NOV. EME Homer City responded by undertaking the indemnity obligation and defense of the claims.

Four Corners CPUC Emissions Performance Standard Ruling

The CPUC adopted a GHG emission performance standard, effective January 2007. In January 2008, SCE filed a petition with the CPUC seeking clarification that the emission performance standard would not apply to capital expenditures required by existing agreements among the owners at Four Corners. The CPUC issued a proposed decision finding that the emission performance standard was not intended to apply to capital expenditures at Four Corners requested by SCE in its General Rate Case for the period 2007 2011. On October 23, 2008, the Assigned Commissioner and Administrative Law Judge issued a ruling withdrawing the proposed decision and seeking additional comment on whether the finding in the proposed decision should be changed and whether SCE should be allowed to recover such capital expenditures. SCE estimates that its share of capital expenditures approved by the owners at Four Corners since the GHG emission performance standard decision was issued in January 2007 is approximately $43 million, of which approximately $8 million had been expended through September 30, 2008. The ruling also directs SCE to explain why certain information was not included in its petition and why the failure to include such information should not be considered misleading in violation of CPUC rules. SCE cannot predict the outcome of this proceeding or estimate the amount, if any, of penalties or disallowances that may be imposed.

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. On March 29, 2007, the FERC issued an order agreeing with SCE s position that the charges incurred by the ISO were related to voltage support and should be allocated to the scheduling coordinators, rather than to SCE as a transmission owner. The Cities filed a request for rehearing of the FERC s order on April 27, 2007. On May 25, 2007, the FERC issued a procedural order granting the rehearing application for the limited purpose of allowing the FERC to give it further consideration. In a future order, FERC may deny the rehearing request or grant the requested relief in whole or in part. SCE believes that the most recent substantive FERC order correctly allocates responsibility for these ISO charges. However, SCE cannot predict the final outcome of the rehearing. If a subsequent regulatory decision changes the allocation of responsibility for these charges, and SCE is required to pay these charges as a transmission owner, SCE may seek recovery in its reliability service rates. SCE cannot predict whether recovery of these charges in its reliability service rates would be permitted.

Leveraged Lease Investments

At September 30, 2008, Edison Capital had a net leveraged lease investment, before deferred taxes, of $53 million in three aircraft leased to American Airlines. American Airlines reported net losses for its first, second and third quarters in 2008 and previously reported losses for a number of years prior to 2006. 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, 2008, American Airlines was current in its lease payments to Edison Capital.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in 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 market 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 market, Midway-Sunset is potentially liable for refunds to purchasers in these markets.

On December 20, 2007, Midway-Sunset entered into a settlement agreement in the amount of $86 million (including interest) with SCE, PG&E, SDG&E and certain California state parties to resolve Midway-Sunset s liability in the FERC refund proceedings. Midway-Sunset concurrently entered into a separate agreement with SCE and PG&E that provides for pro-rata reimbursement to Midway-Sunset by the two utilities of the portions of the agreed to refunds that are attributable to sales made by Midway-Sunset for the benefit of the utilities (Midway-Sunset did not retain any proceeds from power sold into the PX market 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). The settlement, which had been approved previously by the CPUC, was approved by the FERC on April 2, 2008.

During the period in which Midway-Sunset s generation was sold into the PX market, amounts SCE received from Midway-Sunset for its pro-rata share of such sales were credited to SCE s customers against power purchase expenses through the ratemaking mechanism in place at that time. During the second quarter of 2008, SCE reimbursed Midway-Sunset for its pro-rata share of the Midway-Sunset liability in the amount of approximately $43 million. In addition, SCE, as party to the Midway-Sunset settlement agreement, received a $20 million generator refund. The amount reimbursed to and received from Midway-Sunset (net amount of $23 million) were charged/refunded to ratepayers through regulatory mechanisms. SCE s reimbursement to Midway-Sunset and the refund payment received from Midway-Sunset did not impact earnings.

Midwest Generation New Source Review Notice of Violation

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990s and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration requirements and of the New Source Performance Standards of the Clean Air Act, including alleged requirements to obtain a construction permit and to install best available control technology at the time of the projects. The US EPA also alleges that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the Clean Air Act. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. As a result, Midwest Generation is investigating the claims made by the US EPA in the NOV and is developing a litigation strategy. Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations, financial position or cash flows.

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

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

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the D.C. 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 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 March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff but has not yet identified a specific amount of damages claimed.

In April 2004, the D.C. District Court denied SCE s motion for summary judgment and concluded that a 2003 U.S. Supreme Court decision in an on-going 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. In September 2007, the Federal Circuit reversed a lower court decision on remand in the related lawsuit, finding that the U.S. Government had breached its trust obligation in connection with the setting of the royalty rate for the coal supplied to Mohave. Subsequently, the Federal Circuit denied the U.S. Government s petition for rehearing. On October 1, 2008, the U.S. Supreme Court granted the U.S. Government s petition seeking review of the Federal Circuit s September 2007 decision. A decision from the U.S. Supreme Court is expected in mid-2009.

Pursuant to a joint request of the parties, the D.C. District Court granted a stay of the action in October 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. In a joint status report filed on November 9, 2007, the parties informed the court that their mediation efforts had terminated and subsequently filed a joint motion to lift the stay. The parties have also filed recommendations for a scheduling order to govern the anticipated resumption of litigation. The Court granted the motion to lift the stay on March 6, 2008, reinstating the case to the active calendar, but has deferred setting an overall schedule for the action pending a determination of disputes concerning the discoverability of certain Navajo documents. SCE cannot predict the outcome of the Navajo Nation s and Hopi Tribe s complaints against SCE or the ultimate impact on these complaints of the Supreme Court s 2003 decision and the on-going litigation by the Navajo Nation against the U.S. Government in the related case.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.5 billion. SCE and other owners of San Onofre and 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 NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. Beginning October 29, 2008, the maximum deferred premium for each nuclear incident is approximately $118 million per reactor, but not more than approximately $18 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 at least once every five years beginning August 20, 2003. The most recent inflation adjustment took effect on October 29, 2008. Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 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 law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further revenue.

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 approximately $45 million per year. Insurance premiums are charged to operating expense.

Palo Verde Nuclear Generating Station Inspections

The NRC held three special inspections of Palo Verde, between March 2005 and February 2007. The combination of the results of the first and third special inspections caused the NRC to undertake an additional oversight inspection of Palo Verde. This additional inspection, known as a supplemental inspection, was completed in December 2007. In addition, Palo Verde was required to take additional corrective actions based on the outcome of completed surveys of its plant personnel and self-assessments of its programs and procedures. The NRC and APS defined and agreed to inspection and survey corrective actions that the NRC embodied in a Confirmatory Action Letter, which was issued in February 2008. APS is presently on track to complete the corrective actions required to close the Confirmatory Action Letter by mid-2009. Palo Verde operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE estimates that operation and maintenance costs will increase by approximately $23 million (in 2007 dollars) over the two year period 2008 2009, from 2007 recorded costs including overhead costs. SCE is unable to estimate how long SCE will continue to incur these costs. In the 2009 GRC, SCE requested recovery of, and two-way balancing account treatment for, Palo Verde operation and maintenance expenses including costs associated with these corrective actions. If approved, this would provide for recovery of these costs over the three-year GRC cycle.

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, 2010.

SCE filed its latest compliance report in August 2008. Through the use of flexible compliance rules, SCE demonstrated full compliance for the procurement year 2007 and forecasted full compliance for the procurement years 2008 to 2020. It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

Under current CPUC decisions, potential penalties for SCE s inability to achieve its renewable procurement objectives 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.

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RPM Buyers Complaint

On May 30, 2008, a group of entities referring to themselves as the RPM Buyers filed a complaint at the FERC asking that PJM s RPM, as implemented through the transitional base residual auctions establishing capacity payments for the period from June 1, 2008 through May 31, 2011, be found to have produced unjust and unreasonable capacity prices. The RPM Buyers alleged that the absence of price discipline provided by new capacity resources, together with the ability of existing resources to withhold some capacity within the RPM rules, produced capacity prices in the transition period that are not comparable to those that would have been produced in a competitive market or determined under cost-based regulation, and have requested that the FERC order refunds based on that difference.

On July 10, 2008, EME responded to the RPM Buyers complaint asking that it be dismissed based upon various legal precedents. A number of other parties, including PJM, also responded to the RPM Buyers complaint asking that it be dismissed. On September 19, 2008, the FERC dismissed the RPM Buyers complaint, finding that the RPM Buyers had failed to allege or prove that any party violated PJM s tariff and market rules, and that the prices determined during the transition period were determined in accordance with PJM s FERC-approved tariff. On October 20, 2008, the RPM Buyers requested rehearing of the FERC s order dismissing their complaint. This matter is currently pending before the FERC. EME cannot predict the outcome of this matter.

Scheduling Coordinator Tariff Dispute

Pursuant to the Amended and Restated Exchange Agreement, SCE serves as a scheduling coordinator for the DWP over the ISO-controlled grid. In late 2003, SCE began charging the DWP under a tariff subject to refund for FERC-authorized scheduling coordinator and line loss charges incurred by SCE on the DWP s behalf. The scheduling coordinator charges had been billed to the DWP under a FERC tariff that was 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 thus made them subject to refund and further review by the FERC.

In January 2008, an agreement between SCE and the DWP was executed settling the dispute discussed above. The settlement had been previously approved by the FERC in July 2007. The settlement agreement provides that the DWP will be responsible for line losses and SCE would be responsible for the scheduling coordinator charges. During the fourth quarter of 2007, SCE reversed and recognized in earnings (under the caption Purchased power in the consolidated statements of income) $30 million of an accrued liability representing line losses previously collected from the DWP that were subject to refund. As of December 31, 2007, SCE had an accrued liability of approximately $22 million (including $3 million of interest) representing the estimated amount SCE will refund for scheduling coordinator charges previously collected from the DWP. SCE made its first refund payment on February 20, 2008 and the second refund payment was made on February 27, 2008. SCE previously received FERC approval to recover the scheduling coordinator charges from all transmission grid customers through SCE s transmission rates and on December 11, 2007, the FERC accepted SCE s proposed transmission rates reflecting the forecast levels of costs associated with the settlement. Upon signing of the agreement in January 2008, SCE recorded a regulatory asset and recognized in earnings the amount of scheduling coordinator charges to be collected through rates. On July 8, 2008, the FERC approved SCE s refund report.

Spent Nuclear Fuel

Under federal law, the 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

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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. In a Joint Status Report filed on July 1, 2008, the parties requested a trial date in mid-November 2008. On August 6, 2008, the Court set a trial date of April 14 28, 2009.

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 and some of Unit 2 and 3 s spent fuel is stored. SCE, as operating agent, plans to transfer fuel from the Unit 2 and 3 spent fuel pools to the independent storage installation on an as-needed basis to maintain full core off-load capability for Units 2 and 3. There are now sufficient dry casks and modules available at the independent spent fuel storage installation to meet plant requirements through the end of 2008. SCE plans to add storage capacity incrementally to meet the plant requirements until 2022 (the end of the current NRC operating license).

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed an independent spent fuel storage facility. APS, as operating agent, plans to add storage capacity incrementally to maintain full core off-load capability for all three units.

Note 6. Accumulated Other Comprehensive Income (Loss) Information

Edison International s accumulated other comprehensive income (loss) consists of:

In millions	Unrealized Gain (Loss) on Cash Flow Hedges	Foreign Currency Translation Adjustment	Pension and PBOP Net Loss	Pension and PBOP Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
			(Unaudited)		
Balance at December 31, 2007	$ (60)	$ (1)	$ (34)	$ 3	$ (92)
Current period change	150	(4)			146
Balance at September 30, 2008	**$ 90**	**$ (5)**	**$ (34)**	**$ 3**	**$ 54**

Unrealized gains on cash flow hedges, net of tax, at September 30, 2008, included unrealized gains on commodity hedges related to Midwest Generation and EME Homer City futures and forward electricity contracts that qualify for hedge accounting. These gains arise because current forecasts of future electricity prices in these markets are lower than the contract prices. As EME s hedged positions for continuing operations are realized, $46 million, after tax, of the net unrealized gains on cash flow hedges at September 30, 2008 are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized gains will increase energy revenue recognized at market prices. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions. The maximum period over which a cash flow hedge is designated is through December 31, 2011.

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 $23 million and $(13) million during the third quarters of 2008 and 2007, respectively, and $(8) million and $(23) million during the nine months ended September 30, 2008 and 2007,

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respectively, representing the amount of cash flow hedges ineffectiveness for continuing operations, reflected in operating revenues on Edison International s consolidated income statements.

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. EME had power contracts with Lehman Brothers Commodity Services, Inc., a subsidiary of Lehman Brothers Holdings, for Midwest Generation for 2009 and 2010. The obligations of Lehman Brothers Commodity Services under the power contracts are guaranteed by Lehman Brothers Holdings. These contracts qualified as cash flow hedges under SFAS No. 133 until EME designated the power contracts as such, effective September 12, 2008 when it determined that it was no longer probable that performance would occur. The amount recorded in accumulated comprehensive income (loss) related to the effective portion of the hedges was $24 million pre-tax ($15 million, after tax) on this date. Since the power contracts are no longer being accounted for as cash flow hedges under SFAS No. 133, the subsequent change in fair value was recorded as an unrealized loss during the third quarter of 2008 reflected in operating revenues on EME s consolidated statement of income. Under SFAS No. 133, the pre-tax amount recorded in accumulated other comprehensive income (loss) will be reclassified to operating revenues based on the original forecasted transactions in 2009 ($15 million) and 2010 ($9 million), unless it becomes probable that forecasted transactions will no longer occur.

Note 7. Supplemental Cash Flows Information

Edison International s supplemental cash flows information is:

In millions	Nine Months Ended September 30, 2008	2007
	(Unaudited)	
Cash payments (receipts) for interest and taxes:		
Interest net of amounts capitalized	**$ 532**	$ 466
Tax payments (receipts)	**273**	(2)
Noncash investing and financing activities:		
Details of obligation under capital lease:		
Capital lease asset purchased	**$**	$ (10)
Capital lease obligation issued		10
Dividends declared but not paid:		
Common stock	**$ 99**	$ 94
Preferred and preference stock of utility not subject to mandatory redemption	**13**	8
Details of assets acquired:		
Fair value of assets acquired	**$**	$ 41

In connection with certain wind projects acquired during the second quarter of 2008 and the first and third quarters of 2007, the purchase price included payments that were due upon the start and/or completion of construction. Accordingly, during the first nine months of 2008 and 2007, EME accrued for estimated payments that were due upon commencement of construction and/or completion of construction scheduled during 2008 through 2009.

Note 8. Fair Value Measurements

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (referred to as an exit price in SFAS No. 157). SFAS No. 157 clarifies that a fair value measurement for a liability should reflect the entity s non-performance risk. In addition, SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under SFAS No. 157 are:

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets and liabilities;

Level 2 Pricing inputs include quoted prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument; and

Level 3 Prices or valuations that require inputs that are both significant to the fair value measurements and unobservable.

Edison International s assets and liabilities carried at fair value primarily consist of derivative contracts, SCE nuclear decommissioning trust investments and money market funds. Derivative contracts primarily relate to power and gas and include contracts for forward physical sales and purchases, options and forward price swaps which settle only on a financial basis (including futures contracts). Derivative contracts can be exchange traded or over-the-counter traded.

The fair value of derivative contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. Derivatives that are exchange traded in active markets for identical assets or liabilities are classified as Level 1. The majority of EME s derivative contracts used for hedging purposes are based on forward market prices in active markets (PJM West Hub, Northern Illinois Hub and AEP/Dayton) adjusted for non-performance risks. EME obtains forward market prices from traded exchanges (ICE Futures U.S. or New York Mercantile Exchange) and available broker quotes. Then, EME selects a primary source that best represents traded activity for each market to develop observable forward market prices in determining fair value of these positions. Broker quotes or prices from exchanges are used to validate and corroborate the primary source. Broker quotes are considered observable when corroborated with prices from exchanges. The majority of the fair value of EME s derivative contracts determined in this manner are classified as Level 2. SCE s Level 2 derivatives primarily consist of natural gas swaps and natural gas physical trades for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange.

Level 3 includes the majority of SCE s derivatives, including over-the-counter options, bilateral contracts, and capacity and QF contracts. The fair value of these SCE derivatives is determined using uncorroborated broker quotes and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Level 3 also includes derivatives that trade infrequently (such as financial transmission rights, firm transmission rights and CRRs in the California market and over-the-counter derivatives at illiquid locations), derivatives with counterparties that have significant non-performance risks, as discussed below, and long-term power agreements. For illiquid financial transmission rights, firm transmission rights and CRRs, Edison International reviews objective criteria related to system congestion on a quarterly basis and other underlying drivers and adjusts fair value when Edison International concludes a change in objective criteria would result in a new valuation that better reflects the fair value. Changes in fair values are based on the hypothetical sale of illiquid positions. For illiquid long-term power agreements, fair value is based upon a discounting of future electricity prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit risk and market liquidity. Changes in fair value are based on changes to forward market prices, including forecasted prices for illiquid forward periods. In circumstances where Edison International cannot verify fair value with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. As markets continue to develop and more pricing information becomes available, Edison International continues to assess valuation methodologies used to determine fair value.

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In assessing non-performance risks, EME reviews credit ratings of counterparties (and related default rates based on such credit ratings) and prices of credit default swaps. The market price (or premium) for credit default swaps represents the price that a counterparty would pay to transfer the risk of default, typically bankruptcy, to another party. A credit default swap is not directly comparable to the credit risks of derivative contracts, but provides market information of the related risk of non-performance. In light of recent market events, EME utilized market prices for credit default swaps in reducing the fair value of derivative assets with financial institutions by $7 million at September 30, 2008.

Investments in money market funds are generally classified as Level 1 as fair value is determined by observable market prices (unadjusted) in active markets. At September 30, 2008, EME has invested $20 million in the Reserve Primary Fund (a money market fund). The Reserve incurred a loss related to debt securities of Lehman Brothers Holdings and has announced liquidation of the Reserve with the latest valuation of $0.97 per share. EME has reduced the fair value of the investment by $1 million and transferred the remaining balance into Level 3 as observable market prices are not available.

The SCE nuclear decommissioning trust investments include equity securities, U.S. treasury securities and other fixed-income securities. Equity and treasury securities are classified as Level 1 as fair value is determined by observable market prices in active or highly liquid and transparent markets. The remaining fixed-income securities are classified as Level 2. The fair value of these financial instruments is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information.

The following table sets forth financial assets and liabilities that were accounted for at fair value as of September 30, 2008 by level within the fair value hierarchy.

In millions	Level 1	Level 2	Level 3	Netting and Collateral[(1)]	Total at September 30, 2008
			(Unaudited)		
Assets at Fair Value					
Money market funds[(2)]	$ 2,705	$	$ 19	$	$ 2,724
Derivative contracts	2	141	282		425
Nuclear decommissioning trusts[(3)]	1,855	999			2,854
Long-term disability plan		9			9
Total assets[(4)]	4,562	1,149	301		6,012
Liabilities at Fair Value					
Derivative contracts	(2)	(190)	(120)	98	(214)
Net assets	**$ 4,560**	**$ 959**	**$ 181**	**$ 98**	**$ 5,798**

(1) Represents cash collateral and the impact of netting across the levels of the fair value hierarchy. Netting among positions classified within the same level is included in that level.

(2) Included in cash and cash equivalents and short-term investments on Edison International s consolidated balance sheet.

(3) Excludes net assets of $1 million for interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

(4) Excludes $32 million of cash surrender value of life insurance investments for deferred compensation.

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The following table sets forth a summary of changes in the fair value of Level 3 derivative contracts, net for the three- and nine-month periods ended September 30, 2008.

In millions	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
	(Unaudited)	
Fair value of derivative contracts, net at beginning of period	$ 386	$ 98
Total realized/unrealized gains (losses):		
Included in earnings[1]	142	234
Included in regulatory assets and liabilities[2]	(264)	(99)
Included in accumulated other comprehensive income	9	3
Purchases and settlements, net	(36)	11
Transfers in or out of Level 3	(75)	(85)
Fair value of derivative contracts, net at end of period	$ 162	$ 162
Change during the period in unrealized gains (losses) related to net derivative contracts, held at September 30, 2008[3]	$ (79)	$ (14)

(1) $142 million and $234 million reported in Nonutility power generation revenue on Edison International s consolidated statements of income for the three- and nine-month periods ended September 30, 2008, respectively.

(2) $(264) million and $(99) million reported in Purchased power expense and, due to expected recovery through regulatory mechanisms, are offset in Provisions for regulatory adjustment clauses net on Edison International s consolidated statements of income for the three- and nine-month periods ended September 30, 2008, respectively.

(3) $101 million and $56 million reported in Nonutility power generation revenue and $(180) million and $(70) million reported in Purchased power expense on Edison International s consolidated statements of income for the three- and nine-month periods ended September 30, 2008, respectively. Due to expected recovery through regulatory mechanisms, the amounts in Purchased power are offset in Provisions for regulatory adjustment clauses net.

Nuclear Decommissioning Trusts

SCE is collecting in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

Trust investments (at fair value) include:

In millions	Maturity Dates	September 30, 2008	December 31, 2007
		(Unaudited)	
Municipal bonds	2008 2044	**$ 564**	$ 561
Stocks		**1,672**	1,968
United States government issues	2008 2049	**318**	552
Corporate bonds	2008 2047	**267**	241
Short-term	2008 2009	**34**	56
Total		**$ 2,855**	$ 3,378

Note: Maturity dates as of September 30, 2008.

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The following table sets forth a summary of changes in the fair value of the trust for the three- and nine-month periods ended September 30, 2008:

In millions	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
	(Unaudited)	
Balance at beginning of period	$ 3,152	$ 3,378
Realized losses net	(7)	(13)
Unrealized losses net	(240)	(452)
Other-than-temporary impairment	(49)	(121)
Earnings and other	(1)	63
Balance at September 30, 2008	**$ 2,855**	**$ 2,855**

The decrease in the trust investments was primarily due to net unrealized losses and other-than-temporary impairment resulting from a volatile stock market environment.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which effective January 2007, receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The next filing is in April 2009 for contribution changes in 2010. These contributions are determined based on an analysis of the current value of trusts assets and long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates.

Note 9. Regulatory Assets and Liabilities

Regulatory assets included in the consolidated balance sheets are:

In millions	September 30, 2008	December 31, 2007
	(Unaudited)	
Current:		
Regulatory balancing accounts	**$ 260**	$ 99
Energy derivatives	**165**	71
Purchased-power settlements	**2**	8
Deferred firm transmission rights proceeds	**24**	15
Other	**3**	4
	454	197
Long-term:		
Regulatory balancing accounts	**14**	15
Flow-through taxes net	**1,319**	1,110
Unamortized nuclear investment net	**382**	405
Nuclear-related asset retirement obligation investment net	**282**	297
Unamortized coal plant investment net	**81**	94
Unamortized loss on reacquired debt	**315**	331
SFAS No. 158 pensions and postretirement benefits	**240**	231
Energy derivatives	**77**	70
Environmental remediation	**42**	64
Other	**128**	104

		2,880		2,721
Total Regulatory Assets	**$**	**3,334**	$	2,918

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Regulatory liabilities included in the consolidated balance sheets are:

In millions	September 30, 2008 (Unaudited)	December 31, 2007
Current:		
Regulatory balancing accounts	**$ 1,106**	$ 967
Rate reduction notes transition cost overcollection	**20**	20
Energy derivatives	**7**	10
Deferred firm transmission rights costs	**42**	19
Other	**4**	3
	1,179	1,019
Long-term:		
Regulatory balancing accounts	**10**	
Asset retirement obligations	**167**	793
Costs of removal	**2,319**	2,230
SFAS No. 158 pensions and other postretirement benefits	**317**	308
Energy derivatives	**1**	27
Employee benefit plans	**75**	75
	2,889	3,433
Total Regulatory Liabilities	**$ 4,068**	$ 4,452

Note 10. Preferred and Preference Stock Not Subject to Mandatory Redemption

In January 2008, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. SCE retired this preferred stock in January 2008 and recorded a $2 million gain on the cancellation of reacquired capital stock (reflected in the caption Additional paid-in capital on the consolidated balance sheets). There is no sinking fund requirement for redemptions or repurchases of preferred stock.

Note 11. Business Segments

Edison International s reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (EME), and a financial services provider segment (Edison Capital). Included in the nonutility power generation segment are the activities of MEHC, the holding company of EME. MEHC s only substantive activities were its obligations under the senior secured notes which were paid in full on June 25, 2007. MEHC does not have any substantive operations. Edison International evaluates performance of its business segments based on net income.

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and Southern California. SCE also produces electricity. EME is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from electric power generation facilities. EME also conducts hedging and energy trading activities in power markets open to competition. Edison Capital is a provider of financial services with investments worldwide.

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Segment information for the three- and nine-month periods ended September 30, 2008 and 2007 was:

In millions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Unaudited)			
Operating Revenue:				
Electric utility	**$ 3,284**	$ 3,213	**$ 8,388**	$ 7,895
Nonutility power generation	**813**	711	**2,143**	1,952
Financial services	**14**	16	**44**	51
All others[1]		2	**1**	4
Consolidated Edison International	**$ 4,111**	$ 3,942	**$ 10,576**	$ 9,902
Net Income (Loss):				
Electric utility[2]	**$ 235**	$ 262	**$ 542**	$ 587
Nonutility power generation[3]	**209**	190	**427**	256
Financial services	**4**	15	**48**	59
All others[1]	**(9)**	(6)	**(18)**	(15)
Consolidated Edison International	**$ 439**	$ 461	**$ 999**	$ 887

(1) Includes amounts from nonutility subsidiaries, as well as Edison International (parent) that are not significant as a reportable segment.

(2) Net income available for common stock.

(3) Includes earnings (loss) from discontinued operations of $6 million and $(4) million for the three months ended September 30, 2008 and 2007, respectively and none and $1 million for the nine months ended September 30, 2008 and 2007, respectively.

Note 12. Investment in Leveraged Leases, Partnerships and Unconsolidated Subsidiaries

First Energy exercised an early buyout right under the terms of an existing lease agreement with Edison Capital related to Unit No. 2 of the Beaver Valley Nuclear Power Plant. The termination date of the lease under the early buyout option was June 1, 2008. Proceeds from the sale were $72 million. Edison Capital recorded a pre-tax gain of $41 million ($23 million after tax) during the second quarter of 2008.

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

INTRODUCTION

This MD&A for the three- and nine-month periods ended September 30, 2008 discusses material changes in the consolidated financial condition, results of operations and other developments of Edison International since December 31, 2007, and as compared to the three- and nine-month periods ended September 30, 2007. This discussion presumes that the reader has read or has access to Edison International s MD&A for the calendar year 2007 (the year-ended 2007 MD&A), which was included in Edison International s 2007 annual report to shareholders and incorporated by reference into Edison International s Annual Report on Form 10-K for the year ended December 31, 2007, 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, int 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 cost of capital and the ability to borrow funds and access to capital markets on favorable terms, particularly in light of current credit conditions in the capital markets and uncertainty over the global economic outlook;

the availability and creditworthiness of counterparties to enter into hedge transactions to reduce market price risk;

the ability to procure sufficient resources to meet expected customer needs in the event of significant counterparty defaults under power-purchase agreements;

changes in the fair value of investments and other assets;

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 SCE to recover its costs in a timely manner from its customers through regulated rates;

decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;

market risks affecting SCE s energy procurement activities;

changes in interest rates, rates of inflation beyond those rates which may be adjusted from year to year by public utility regulators, 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;

environmental laws and regulations, both at the state and federal levels, 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;

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the cost and 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;

creditworthiness of suppliers and other project participants and their ability to deliver goods and services per their contractual obligations to EME and its subsidiaries;

the outcome of disputes with the IRS and other tax authorities regarding tax positions taken by Edison International;

the continued participation of Edison International s subsidiaries in tax-allocation and payment agreements;

supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which EMG s generating units have access;

the cost and availability of coal, natural gas, fuel oil, nuclear fuel, and associated transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;

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 counterparty default in hedging transactions or power-purchase and 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 aspects of 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 the risks inherent in the development of generation projects as well as transmission and distribution infrastructure replacement and expansion including those related to siting, financing, construction, permitting, and governmental approvals.

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. 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 & 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, a rate-regulated electric utility, and EMG. EMG is the holding company for its principal wholly owned subsidiaries, EME, which is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities, and Edison Capital, a provider of capital and financial services.

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In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, EMG, EME or Edison Capital mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company mean Edison International on a stand-alone basis, not consolidated with its subsidiaries.

This MD&A is presented in 8 major sections. The company-by-company discussion of SCE, EMG, and Edison International (parent) includes 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 most important. This section is not intended to be an all-inclusive list of all current developments related to each principal business segment and should be read together with all sections of this MD&A.

EDISON INTERNATIONAL: CURRENT DEVELOPMENTS

Financial Markets and Economic Conditions

Global financial markets are experiencing severe credit tightening and a significant increase in volatility, causing access to capital markets to become subject to increased uncertainty and borrowing costs to rise dramatically. In response, U.S. and foreign governments and Central Banks have intervened with programs designed to increase liquidity.

Edison International s subsidiaries are capital intensive businesses and depend on access to the financial markets to fund capital expenditures, meet contractual obligations and support margin and collateral requirements. SCE has significant planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. EMG has plans to expand its business development activities to grow and diversify its existing portfolio of power projects, including building new power plants, meeting its environmental commitments and making ongoing capital improvements to its existing generation fleet, all of which require liquidity and access to capital markets in the future. See SCE: Liquidity, EMG: Liquidity, and Commitments, Guarantees and Indemnities for further discussion.

Due to the instability of the financial markets, and to provide protection against a dramatic liquidity crisis, in September 2008 Edison International and its subsidiaries borrowed under their various credit facilities a total of $2.1 billion (including $958 million for SCE, $898 million for EMG, and $250 million for Edison International (parent)), although there was no immediate need for such funds. The proceeds from these borrowings were invested in U.S. treasury securities and U.S. treasury and government agency money market funds. As of September 30, 2008, Edison International had $5.4 billion of available liquidity made up of $3.5 billion of cash and short-term investments, as well as $1.9 billion available under the credit facilities. In addition, in October 2008, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014. The bond proceeds further augmented SCE s cash position. Edison International and its subsidiaries do not have any material debt obligations that mature until 2012. See SCE: Liquidity and EMG: Liquidity for further discussion.

While the capital markets are expected to recover over time, it is uncertain how long before a recovery occurs. The level of future growth for SCE will largely be dependent on the outcome of SCE s 2009 GRC (see SCE: Liquidity Capital Expenditures and SCE: Regulatory Matters Current Regulatory Developments 2009 General Rate Case Proceeding). Also, SCE relies on power-purchase contracts to meet its resource requirements. The financial crisis may adversely affect the ability of counterparties to access the capital markets, as needed, to perform under contracts upon which SCE will rely to meet new generation and RPS requirements. Additionally, if counterparties fail to deliver under power-purchase contracts, SCE would be exposed to potentially volatile spot markets for buying replacement power, but would expect to recover any additional costs through regulatory mechanisms. The volatile market conditions have also affected the value of trusts established at SCE to fund future long-term pension, other postretirement benefits, and nuclear decommissioning obligations. The market decline has eroded the funded status of these plans and unless the market recovers, will result in increased future expense and higher funding levels. SCE currently recovers and expects to continue to recover its pension, other postretirement benefits, and decommissioning costs, through customer rates and therefore funded cost increases are not expected to impact earnings, but may impact the timing of cash flows (see SCE: Liquidity and SCE: Other Developments for further discussion).

EMG has made substantial capital commitments, especially for wind turbines. Pending recovery of the capital markets, EMG intends to preserve capital by focusing on a more selective growth strategy (primarily completion of projects under construction, including the Big Sky project in Illinois, and development of sites for future renewable projects deploying current turbine commitments), and using its cash and future cash flow to meet its existing contractual commitments. Moreover, disruption in the financial markets appears to have reduced trading activity in power markets which may affect the level and duration of future hedging activity and potentially increase the volatility of earnings. See EMG: Liquidity for further discussion. Long-term disruption in the capital markets could adversely affect Edison International s business plans and potentially impact Edison International s financial position.

Bankruptcy of Lehman Brothers Holdings and Subsidiaries

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Three subsidiaries of Lehman Brothers Holdings are lenders in SCE s, EMG s and Edison International (parents) s credit agreements representing, a total commitment of $260 million ($106 million for SCE, $80 million for EMG, and $74 million for Edison International (parent)). In September 2008, two of the three Lehman Brothers Holdings subsidiaries declined requests for funding under SCE s and one of EMG s credit agreements.

Another subsidiary of Lehman Brothers Holdings, Lehman Brothers Commodity Services, Inc., declined to meet a collateral call on power contracts at EMG, including hedge contracts for Midwest Generation for 2009 and 2010. The obligations of this Lehman Brothers Commodity Services, Inc. under the power contracts are guaranteed by Lehman Brothers Holdings. On October 3, 2008 Lehman Brothers Commodity Services, Inc. filed for protection under Chapter 11. The bankruptcy filings and failure to post collateral are events of default under the related agreements. In October 2008, these power contracts were terminated, resulting in claims against Lehman Brothers Holdings and its subsidiary in bankruptcy. As a result of the termination, EME recorded a pre-tax loss of $26 million related to power contracts during the third quarter of 2008 reflected in nonutility power generation revenue on Edison International s consolidated statement of income. See EMG: Market Risk Exposures Accounting for Energy Contracts.

Federal and State Income Taxes

Edison International is currently engaged in settlement negotiations with the IRS to reach a Global Settlement which, if consummated, would resolve cross-border, leveraged lease issues in their entirety and all other outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. See Edison International Notes to Consolidated Financial Statements Note 3. Income Taxes. These negotiations have progressed to the point where Edison International and the IRS have reached nonbinding, preliminary understandings on the material principles for resolving the lease issues as part of the resolution of all issues included in the Global Settlement. Final resolution of such disputes, as part of the Global Settlement, is subject to reaching definitive agreements on final terms and calculations, mutually satisfactory documentation, and review of all or a portion of the Global Settlement by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the Joint Committee). While not assured, Edison International believes that the Global Settlement will be submitted or substantially ready to be submitted to the Joint Committee during the fourth quarter of 2008. See Other Developments Federal and State Income Taxes for further information.

Enterprise-Wide Software System Project

On July 1, 2008, Edison International implemented SAP s Enterprise Resource Planning system for financial, supply chain, and certain work management modules at SCE. In addition, Edison International also implemented the human resources module including payroll and timekeeping, at SCE and EMG. Edison International expects to implement additional SAP modules in the future.

SCE: CURRENT DEVELOPMENTS

Investigation Regarding Performance Incentives Rewards CPUC Decision

On September 18, 2008, the CPUC adopted a decision in its investigation into SCE s incentives claimed under a CPUC-approved PBR mechanism that allowed SCE to earn rewards or incur penalties for the period 1997 2003 based on its performance in comparison to CPUC-approved standards of customer satisfaction and employee safety reporting. The adopted decision required refunds or to forego incentives of $48 million and $35 million related to previous customer satisfaction and employee safety reporting incentives, respectively. The decision also required SCE to refund $33 million for employee bonuses and imposed a statutory penalty of $30 million. During the third quarter, SCE recorded a charge of $49 million, after-tax reflected primarily in Other nonoperating deductions in the consolidated statements of income related to this decision. See SCE: Regulatory Matters Current Regulatory Developments Investigations Regarding Performance Incentives Rewards for further discussion.

2009 General Rate Case Proceeding

SCE filed its GRC application requesting a 2009 base rate revenue requirement of $5.16 billion. After considering the effects of sales growth and other offsets, SCE s request would be a $695 million increase over current authorized base rate revenue. On April 15, 2008, the DRA recommended that SCE s 2009 base rate revenue requirement be increased by approximately $19 million, $676 million less than SCE s revised request, mainly due to reductions in capital-related costs, operating and maintenance expense, administrative and general expense, and other miscellaneous proposed reductions. Testimony submitted by TURN, another intervenor, sought to reduce SCE s 2009 request by an additional $195 million over the DRA proposed adjustments, mainly due to reduced depreciation expense. In September 2008, SCE submitted updated testimony, limited to changes in the escalation rate forecast and known changes due to governmental action which increased the requested 2009 base rate revenue requirement to $5.21 billion, an increase of $739 million over current authorized base rate revenue. See SCE: Regulatory Matters Current Regulatory Developments 2009 General Rate Case Proceeding for further discussion. A final decision is expected prior to year-end 2008.

2009 FERC Rate Case

In September 2008, the FERC accepted SCE s revisions to its Transmission Owner Tariff, effective on March 1, 2009, subject to refund and settlement procedures. The revisions reflected changes to SCE s transmission revenue requirement and transmission rates for customers taking service over SCE s transmission facilities.

SCE requested a $129 million increase in its retail transmission revenue requirements (or a 39% increase over the current retail transmission revenue requirement). The requested increase amounts to a 1.2% system average rate increase due to an increase in transmission capital-related costs and increases in transmission operating and maintenance expenses that SCE expects to incur in 2009 to maintain grid reliability. The transmission revenue requirement is based on an overall return on equity of 12.7%, which is composed of a 12.0% base ROE and 0.7% in transmission incentives previously approved by the FERC (see SCE: Regulatory Matters Current Regulatory Developments FERC Construction Work in Progress Mechanism for further information). As discussed in SCE: Liquidity Capital Expenditures, SCE has significant planned expenditures to replace and expand its transmission infrastructure.

Solar Photovoltaic Program

On March 27, 2008, SCE filed an application with the CPUC to implement its Solar Photovoltaic (PV) Program to develop up to 250 MW of utility-owned Solar PV generating facilities ranging in size from 1 to 2 MW each. Targeted at commercial and industrial rooftop space in SCE s service territory, SCE s program will use rooftop space from entities that would not otherwise be typical candidates for the net energy metering tariff, which allows customers to offset their usage with electricity generated at their own facilities. SCE proposes to develop

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these projects at a rate of approximately 50 MW per year at an average cost of $3.50/watt. The estimated base case capital cost for the Solar PV Program is $875 million (2008 dollars) over the period of the program (2008 2013). SCE proposes a reasonableness threshold of $963 million in nominal dollars. Subject to CPUC approval, the capital expenditures will be eligible to be included in SCE s earning asset base if the actual costs of the program are equal to or lower than the reasonableness threshold amount. SCE also proposes to apply the CPUC-approved 100 basis point incentive adder to SCE s allowed rate of return on rate base on the project as allowed by the CPUC decision for qualifying utility-owned renewable energy generation facilities. In September 2008, the CPUC granted SCE s request to track costs spent on projects up to $25 million incurred prior to the receipt of the CPUC s final decision in a memorandum account for potential future recovery. SCE expects to continue to move forward with projects in advance of the final CPUC decision subject to the authorized tracking account mechanism. In September 2008, several parties filed testimony opposing SCE s Solar PV program application. Evidentiary hearings are scheduled for November 2008 and a final decision for March 2009. SCE cannot predict the final outcome of this proceeding.

EMG: CURRENT DEVELOPMENTS

Industry Developments

Commodity Prices

Since June 30, 2008, forward energy prices have decreased substantially driven by lower natural gas prices and the financial market developments discussed above. The forward energy market prices for 2009 and 2010 at September 30, 2008 for the Northern Illinois Hub and PJM West Hub have decreased between 13% and 30% since June 30, 2008. At September 30, 2008, EME had entered into derivative hedge contracts that are recorded at fair value on its consolidated financial statements. Since forward energy prices have decreased since June 30, 2008, the fair value of derivative hedge contracts changed from a net liability position at June 30, 2008 to a net asset position at September 30, 2008, with the effective portion of the contracts recorded as an increase in shareholder s equity ($90 million, after tax). See EMG: Market Risk Exposures Commodity Price Risk for further discussion.

Regulatory Developments

In July 2008, a three-judge panel of the District of Columbia Circuit Court of Appeals issued a decision to vacate the CAIR in its entirety and remand to the US EPA to issue a new rule consistent with the decision. In September 2008, US EPA and other parties requested a rehearing of its decision by the same three-judge panel or by the full District of Columbia Circuit Court. In October 2008, the Court ordered the petitioners in the CAIR litigation to file a response to the request for rehearing and specifically address whether any party is seeking to vacate the CAIR and whether the Court should stay its mandate until the US EPA promulgates a revised rule. Although EME cannot predict the outcome of this proceeding, this latest order suggests that the Court may be willing to leave the CAIR in place in some form. The Court s order vacating the CAIR will not become effective until the Court responds to the petitions for a rehearing of its decision; until then, compliance with the CAIR, including the annual NO_X requirements, will be required. If the Court denies the petitions for rehearing and issues a mandate to vacate the CAIR, there will be substantial uncertainty as to the impact of this decision on the SIP regulations promulgated by Pennsylvania and Illinois in response to the CAIR.

Notwithstanding these developments, the Illinois plants and Homer City facilities continue to be governed by state rules as well as the existing SIP Call ozone season NO_X cap-and-trade program (which was due to be replaced by the CAIR). For further discussion, see Other Developments Environmental Matters Air Quality Regulation Clean Air Interstate Rule.

Based on the CAIR requirements, Midwest Generation purchased annual NO_X allowances under the new CAIR annual NO_X program. Midwest Generation and EME Homer City continue to plan to meet the requirements of the CAIR as required under current law effective January 1, 2009. If the D.C. Circuit Court issues a mandate to vacate the CAIR, Midwest Generation would no longer need annual NO_X allowances and would record an impairment of $48 million at the time of such action.

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Extension of Production Tax Credits

New wind projects currently receive federal subsidies in the form of production tax credits. Production tax credits for a ten-year period are available for new projects placed in service prior to December 31, 2008. In October 2008, production tax credits were extended for projects placed in service by December 31, 2009 as part of the Emergency Economic Stabilization Act of 2008.

Growth Activities

Renewable Energy

At September 30, 2008, EME had 855 MW of wind projects in service and another 330 MW of wind projects under construction, with scheduled completion dates into 2009. As of the same date, EME had a development pipeline of potential wind projects with an estimated installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. This development pipeline is supported by turbine purchase commitments totaling 942 MW for new wind projects. The majority of the turbines are scheduled to be delivered before the end of 2010.

Key activities during the third quarter of 2008 with respect to wind projects were:

- Commenced construction of the 100 MW High Lonesome wind project located in New Mexico.

- Completed construction and commenced operations of the 61 MW Mountain Wind I and 80 MW Mountain Wind II wind projects both located in Wyoming and the 19 MW Spanish Fork wind project located in Utah.

Thermal Energy

During the first quarter of 2008, a subsidiary of EME was awarded through a competitive bidding process a ten-year power sales contract with SCE for the output of a 479 MW gas-peaking facility located in the City of Industry, California, which is referred to as the Walnut Creek project. The power sales agreement was approved by the CPUC on September 18, 2008 and by the FERC on October 2, 2008. Deliveries under the power sales agreement are expected to commence in 2013. During the second quarter of 2008, EME and its subsidiary entered into an agreement to purchase major equipment for the project. See EMG: Liquidity Capital Expenditures Expenditures for New Projects for further details on the status of this project, including uncertainty regarding availability of emissions credits.

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SOUTHERN CALIFORNIA EDISON COMPANY

SCE: LIQUIDITY

Overview

In light of current market conditions, SCE borrowed against its credit facility in September 2008 and issued bonds in October 2008 to ensure the availability of funds to meet its future cash requirements. The proceeds were invested in U.S. treasury bills and U.S. treasury and government agency money market funds. As of September 30, 2008, SCE had cash and equivalents of $1.26 billion ($118 million of which was held by SCE s consolidated VIEs).

On March 12, 2008, SCE amended its existing $2.5 billion credit facility, extending the maturity to February 2013 while retaining existing borrowing costs as specified in the facility. The amendment also provides four extension options which, if all exercised, and agreed to by lenders, will result in a final termination in February 2017.

The following table summarizes the status of the SCE credit facility at September 30, 2008:

In millions	**SCE**
Commitment	$ 2,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(81)
	2,419
Outstanding borrowings	(1,558)
Outstanding letters of credit	(233)
Amount available	$ 628

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB is one of the lenders in SCE s credit agreement representing a total commitment of $106 million. In September 2008, Lehman Brothers Bank, FSB declined requests for funding of the most recent borrowings, or approximately $42 million.

As of September 30, 2008, SCE s long-term debt, including current maturities of long-term debt, was $5.86 billion. In October 2008, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014.

SCE s estimated cash outflows during the 12-month period following September 30, 2008 are expected to consist of:

Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct and replace major components of generation assets (see Capital Expenditures below);

Dividend payments to SCE s parent company. The Board of Directors of SCE declared a $25 million dividend to Edison International which was paid in January 2008 and three $100 million dividends which were paid in April 2008, July 2008, and October 2008, respectively;

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

Maturity and interest payments on short- and long-term debt outstanding;

General operating expenses; and

Pension and PBOP trust contributions (see Pension and PBOP trusts below).

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As discussed above, SCE has increased its cash position and expects to meet its continuing obligations, including cash outflows for operating expenses and power-procurement, through cash and equivalents on hand and operating cash flows. Projected capital expenditures are also expected to be financed through cash and cash equivalents on hand and operating cash flows and incremental capital market financings of long-term debt and preferred equity. SCE expects that it would also be able to draw on the remaining availability of its credit facility and access capital markets if additional funding and liquidity is necessary to meet the estimated capital requirements but given current market developments there can be no assurance.

On February 13, 2008, President Bush signed the Economic Stimulus Act of 2008 (2008 Stimulus Act). The 2008 Stimulus Act includes a provision that provides accelerated bonus depreciation for certain capital expenditures incurred during 2008. Edison International expects that certain capital expenditures incurred by SCE during 2008 will qualify for this accelerated bonus depreciation, which would provide additional cash flow benefits estimated to be approximately $175 million for 2008. Any cash flow benefits resulting from this accelerated depreciation should be timing in nature and therefore should result in a higher level of accumulated deferred income taxes reflected on SCE s consolidated balance sheets. Timing benefits related to deferred taxes will be incorporated into future ratemaking proceedings, impacting future period cash flow and rate base.

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

Capital Expenditures

As discussed under the heading SCE: Liquidity Capital Expenditures in the year-ended 2007 MD&A, SCE has significant planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. SCE s 2008 through 2012 capital forecast includes total expenditures of up to $19.9 billion, including capital investments for SCE s Solar PV Program. Certain of these expenditures are subject to regulatory approvals. During the three- and nine-month periods ended September 30, 2008, SCE s capital expenditures were $383 million and $1.55 billion, respectively, compared to a forecast of $2.1 billion for the nine months ended September 30, 2008. SCE s 2008 capital expenditures are likely to be less than the forecast for 2008, primarily due to delays in transmission investments. SCE expects to update its 5-year capital forecast after receiving a final decision in its 2009 GRC. The developments in the financial markets, regulatory decisions, and the economic conditions in the U.S. may alter SCE s capital expenditures plan. See Edison International: Current Developments Financial Markets and Economic Conditions for further discussion.

Pension and PBOP Trusts

Volatile market conditions have affected the value of Edison International s trusts established to fund its future long-term pension benefits and other postretirement benefits. The market value of the investments within the pension and PBOP plan trusts declined 22% and 21%, respectively, during the nine months ended September 30, 2008. These benefit plan assets and related obligations are remeasured annually using a December 31 measurement date. Unless the market recovers, reductions in the value of plan assets will result in: increased future expense; a change in the pension plan funding status from overfunded to underfunded; an increase in the PBOP plan underfunded status; and increased future contributions. Changes in the plan s funded status will affect the assets and liabilities recorded on the balance sheet in accordance with SFAS No. 158. Due to SCE s regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts (see SCE: Regulatory Matters Current Regulatory Developments 2009 General Rate Case Proceeding for further discussion). The Pension Protection Act of 2006 establishes new minimum funding standards and prohibits plans underfunded by more than 20% from providing lump sum distributions and adopting amendments that increase plan liabilities.

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Credit Ratings

At September 30, 2008, SCE s credit ratings were as follows:

	Moody s Rating	S&P Rating	Fitch Rating
Long-term senior secured debt	A2	A	A+
Short-term (commercial paper)	P-2	A-2	F-1

SCE credit ratings have remained consistent with the ratings that existed at year-end 2007. SCE cannot provide assurance that its current credit ratings will remain in effect for any given period of time or that one or more of these ratings will not be changed. These credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

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%. At September 30, 2008, SCE determined compliance with this capital structure based on a 13-month weighted-average calculation. At September 30, 2008, SCE s 13-month weighted-average common equity component of total capitalization was 50.6% resulting in the capacity to pay $333 million in additional dividends.

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, 2008, SCE s debt to total capitalization ratio was 0.50 to 1.

Margin and Collateral Deposits

SCE has entered into certain margining agreements for power and natural 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, changes in market prices relative to contractual commitments, and other factors. Future collateral requirements may be higher (or lower) than collateral requirements at September 30, 2008, due to the addition of incremental power and energy procurement contracts with margining agreements, if any, and the impact of changes in wholesale power and natural gas prices on SCE s contractual obligations.

Certain requirements to post cash and/or collateral (primarily for changes in fair value and accounts payables on delivered energy transactions) are triggered if SCE s credit ratings were downgraded to below investment grade.

In millions	
Collateral posted as of September 30, 2008[1]	$ 295
Incremental collateral requirements resulting from a downgrade of SCE s credit rating to below investment grade	282
Total posted and potential collateral requirements[2]	$ 577

(1) Collateral posted consisted of $52 million which were offset against net derivative liabilities in accordance with the implementation of FIN 39-1, and $243 million provided to counterparties and other brokers (consisting of $10 million in cash reflected in Margin and collateral deposits on the consolidated balance sheets and $233 million in letters of credit).

(2) Total posted and potential collateral requirements may increase by an additional $183 million, based on SCE s forward position as of September 30, 2008, due to adverse market price movements over the remaining life of the existing contracts using a 95% confidence level.

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SCE s incremental collateral requirements are expected to be met from liquidity available from cash on hand of $1.26 billion at September 30, 2008, and available capacity of $628 million under SCE s $2.5 billion credit facility, discussed above.

SCE: REGULATORY MATTERS

Current Regulatory Developments

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

Impact of Regulatory Matters on Customer Rates

The following table summarizes SCE s system average rates and the portion related to CDWR which is not recognized as revenue by SCE, but included in the SCE system average rate, at various dates in 2007 and 2008:

Date	SCE System Average Rate	Portion Related to CDWR
January 1, 2007	14.5¢ per-kWh	3.1¢ per-kWh
February 14, 2007	13.9¢ per-kWh	3.0¢ per-kWh
January 1, 2008	13.8¢ per-kWh	2.9¢ per-kWh
March 1, 2008	13.9¢ per-kWh	2.9¢ per-kWh
April 7, 2008	13.8¢ per-kWh	2.9¢ per-kWh
June 1, 2008	13.7¢ per-kWh	2.8¢ per-kWh

The rate changes in 2008 resulted from the following:

March 2008: Increase to the FERC jurisdictional base transmission rates to include adopted CWIP incentives. See FERC Construction Work in Progress Mechanism for further discussion.

April 2008: Consolidation of the 2008 authorized CPUC jurisdictional revenue requirements. This decrease was primarily related to an increase in estimated 2008 kWh sales which more than offset a small increase in 2008 CPUC authorized revenue requirements.

June 2008: Decrease to the CDWR-related rates.

2009 General Rate Case Proceeding

As discussed under the heading Regulatory Matters Current Regulatory Developments 2009 General Rate Case Proceeding in the year-ended 2007 MD&A, SCE filed its GRC application on November 19, 2007. The application requested a 2009 base rate revenue requirement of $5.2 billion. Hearings and briefings were completed by August 2008. At the end of the hearings, SCE agreed to several adjustments to its request and revised its forecasts to reflect lower customer growth and meter connections due to the economic downturn in southern California. SCE s revised request for 2009 was $5.16 billion. In September 2008, SCE filed updated testimony which was limited to changes in the escalation rate forecast and known changes due to governmental action that increased SCE s request for 2009 to $5.21 billion. After considering the effects of sales growth and other offsets, SCE s revised request would be a $739 million increase over current authorized base rate revenue. If the CPUC approves these requested increases and allocates them to ratepayer groups on a system average percentage change basis, the percentage increases over current base rates and total rates are estimated to be 16.54% and 6.33%, respectively. The revised request would result in 2010 and 2011 base rate revenue requirement increases, net of sales growth, of $211 million and $256 million, respectively. As a result of SCE s post-hearing revised request, the DRA s recommended increase of approximately $19 million, which was submitted on April 15, 2008, represented a difference of $676 million from SCE s post-hearing revised base rate revenue. The $676 million difference is mainly due to reductions proposed by DRA including: a reduction in

capital-related costs of approximately $186 million, which includes recommended changes in methods for calculating depreciation expense; a reduction in operating and maintenance expense of approximately $286 million; a reduction in administrative and general expense of approximately $192 million mainly related to a reduction in pension and benefits, the elimination of results sharing as well as a reduction in long-term incentives and other executive compensation; and other miscellaneous proposed reductions. Additionally, as a result of SCE s post-hearing revised request, TURN s recommendation sought to reduce SCE s post-hearing revised 2009 request by an additional $195 million over the DRA adjustments, primarily due to a further reduction in depreciation expenses.

SCE cannot predict the revenue requirement the CPUC will ultimately authorize or precisely when a final decision will be adopted, although a final decision is expected prior to year-end.

2008 Cost of Capital Proceeding

On December 21, 2007, the CPUC granted SCE s requested rate-making capital structure of 43% long-term debt, 9% preferred equity and 48% common equity for 2008. The CPUC also authorized SCE s 2008 cost of long-term debt of 6.22%, cost of preferred equity of 6.01% and a return on common equity of 11.5%. The impact of this Phase I decision resulted in a $7 million decrease in SCE s 2008 annual revenue requirement. On May 29, 2008, the CPUC issued a final decision on Phase II of the proceeding, replacing the former annual cost of capital application with a multi-year mechanism, which would not require a new cost of capital application to be filed until April 2010. The decision also adopted a trigger mechanism which provides for an automatic adjustment to return on equity and embedded costs of long-term debt and preferred equity during the intervening years between the cost of capital filings if certain thresholds are reached. At the end of September 2008, the trigger threshold was not reached for an automatic adjustment to the 2008 authorized return on equity and embedded costs of long-term debt and preferred equity for 2009. SCE s next adjustment opportunity will occur at the end of September 2009, effective for 2010. As a result, depending on financial market conditions, SCE is exposed to financing costs that are above SCE s authorized rates of 6.22% and 6.01% for new long-term debt and preferred equity financings, respectively, during 2009 which could impact earnings.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

As discussed under the heading SCE: Regulatory Matters Energy Efficiency Shareholder Risk/Reward Incentive Mechanism in the year-ended 2007 MD&A, the CPUC issued a decision in September 2007 that adopted an Energy Efficiency Risk/Reward Incentive mechanism. The mechanism allows for both incentives and economic penalties based on SCE s performance toward meeting CPUC goals for energy efficiency.

Under this mechanism, the timing and amount of claims is linked to the completion of CPUC reports including a verification report on all SCE energy savings estimates, customer benefits, and cost estimates. The first progress payment, for SCE s 2006-2007 energy efficiency portfolio performance, was to be filed in September 2008. SCE was not able to file its request for the first progress payment as a result of a delay in the CPUC s verification report, which is now expected in January 2009.

In July 2008, the Natural Resources Defense Council filed a request with the CPUC for an alternative dispute resolution process to address the first progress payment. While SCE committed to participation in the process, the alternate dispute resolution process has not led to a timely result for the first progress payment.

As another alternate means to receive the first progress payment, SCE and the other California investor-owned utilities filed a petition with the CPUC in August 2008. On November 4, 2008, the CPUC issued a proposed decision and an alternate proposed decision on the utilities petition.

The proposed decision denies the utilities petition and, if adopted, would result in the current process for earnings to continue without alteration. As a result, SCE s first progress payment for 2006 2007 energy efficiency portfolio performance would be based on the CPUC verification report using updated cost effectiveness metrics. The CPUC verification report may result in further reductions to SCE s projected saving and earnings amounts, beyond what was taken into account when calculating its first progress payment in the range of $41 million to $49 million.

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The alternate proposed decision, if adopted, would approve SCE s first progress payment for SCE s 2006 2007 energy efficiency portfolio performances based on total earnings of $71 million, using SCE s quarterly savings reports rather than the CPUC verification report. However, the holdback percentage would be increased from the current approved 35% to 50%, resulting in a first progress payment of $35 million (rather than $46 million, as requested in the petition) which would be recognized upon final approval of the alternate proposed decision. Future progress payments would be based on CPUC verification reports. If the CPUC s verification report is again delayed in 2009, the CPUC may approve a second interim payment based upon SCE s saving reports, subject to another review of the progress payment holdback percentage.

SCE expects a final decision on the utilities petition in December 2008. Actual earnings may differ from SCE s previous projections and there is no assurance of earnings in any given year.

FERC Transmission Incentives

On November 16, 2007, the FERC issued an order granting incentives on three of SCE s largest proposed transmission projects:

A 125 basis point ROE adder on SCE s future proposed base ROE (ROE Adder) for DPV2, which is a high voltage (500 kV) transmission line from the Valley substation to the Devers substation near Palm Springs, California to a new substation near Palo Verde, west of Phoenix, Arizona;

A 125 basis point ROE Adder for the Tehachapi Transmission Project, which is an eleven segment project consisting of newly-constructed and upgraded transmission lines and associated substations to interconnect renewable generation projects near the Tehachapi and Big Creek area; and

A 75 basis point ROE Adder for the Rancho Vista Substation Project, which is a new 500 kV substation in the City of Rancho Cucamonga. The order also grants a higher return on equity on SCE s entire transmission rate base in SCE s next FERC transmission rate case for SCE s participation in the CAISO. In September 2008, the FERC accepted SCE s revisions to its Transmission Owner Tariff, with a requested effective date of March 1, 2009 subject to refund and settlement procedures. In addition, the order permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction, also known as CWIP, of all three projects and 100% recovery of prudently-incurred abandoned plant costs for DPV2 and Tehachapi, if either or both of these projects are cancelled due to factors beyond SCE s control.

In June 2008, the FERC rejected petitions filed by certain parties, including the CPUC, to address the CAISO higher return and the ROE project adders. In August 2008, the CPUC filed an appeal of the FERC incentives order at the DC Circuit Court of Appeals.

FERC Construction Work in Progress Mechanism

As discussed under the heading FERC Construction Work in Progress Mechanism in the year-ended 2007 MD&A and FERC Transmission Incentives above, on December 21, 2007, SCE filed a revision to its Transmission Owner Tariff to collect 100% of CWIP in rate base for its Tehachapi, DPV2, and Rancho Vista projects. In the CWIP filing, SCE proposed a rate adjustment ($45 million or a 14.4% increase) to SCE s currently authorized base transmission revenue requirement to be made effective on March 1, 2008 and later adjusted for amounts actually spent in 2008 through a new balancing account mechanism. The rate adjustment represents actual expenditures from September 1, 2005 through November 30, 2007, projected expenditures from December 1, 2007 through December 31, 2008, and a ROE (which includes the ROE adders approved for Tehachapi, DPV2 and Rancho Vista). The rate adjustment is based on a projection that SCE will spend a total of approximately $244 million, $27 million, and $181 million for Tehachapi, DPV2, and Rancho Vista, respectively, from September 1, 2005 through the end of 2008. The 2008 DPV2 expenditure forecast is limited to projected consulting and legal costs associated with SCE s continued efforts to obtain regulatory approvals necessary to construct the DPV2 Project. On February 29, 2008, the CWIP filing was approved and SCE implemented the CWIP rate on March 1, 2008, subject to refund on the limited issue of whether SCE s proposed ROEs are reasonable. On March 28, 2008, the CPUC filed a petition for rehearing with the FERC on the FERC s acceptance of SCE s proposed ROE for CWIP. Briefs addressing the appropriate ROE were filed by SCE and intervenors in May 2008. In addition, in the order, SCE was directed by FERC to make a compliance filing to provide greater detail on the costs reflected in CWIP rates for 2008. SCE made the compliance filing on March 31, 2008. On April 21, 2008, the CPUC filed a protest of the compliance filing at FERC and requested an evidentiary hearing to be set to further review the costs. SCE filed a response to the CPUC s protest on May 6, 2008 arguing that the FERC should deny the CPUC s request for a further hearing. SCE cannot predict the outcome of the matters in this proceeding.

SCE filed its 2009 update to its CWIP rate adjustment on October 31, 2008. SCE proposed a reduction to its CWIP revenue requirement from $45 million to $39 million to be effective on January 1, 2009.

Energy Resource Recovery Account Proceedings

As discussed under the heading SCE: Regulatory Matters Current Regulatory Developments Energy Resource Recovery Account Proceedings in the year-ended 2007 MD&A, the ERRA is the balancing account mechanism to track and recover SCE s fuel and procurement-related costs. At September 30, 2008, the ERRA was under-collected by $181 million, which was 3.4% 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 under-collection exceeds 5% of SCE s prior year generation revenue (base generation and procurement costs). If SCE files an ERRA trigger application in the fourth quarter of 2008, it is anticipated that the associated rate increase would be implemented during the first quarter of 2009.

2009 ERRA Forecast

In September 2008, SCE filed its 2009 ERRA forecast application estimating its 2009 ERRA revenue requirement to be $4.69 billion, an increase of $984 million over SCE s adopted 2008 ERRA revenue requirement. However, for rate-making purposes, SCE proposed to only increase rates by $342 million to remove the 2007 ERRA over-collected balance reflected as a reduction to current rates. Based on lower forecasts of natural gas prices in 2009, among other things, SCE expects to revise its 2009 ERRA forecast downward.

To the extent the under-collection exceeds 5% of SCE s prior year s generation revenue, as discussed in the year-ended 2007 MD&A under the heading, SCE: Regulatory Matters Current Regulatory Developments Energy Resource Recovery Account Proceedings, SCE expects to use the ERRA balancing account trigger mechanism to recover incremental actual under-collections, if any, that may occur.

Peaker Plant Generation Projects

As discussed under the heading SCE: Regulatory Matters Current Regulatory Developments Peaker Plant Generation Projects in the year-ended 2007 MD&A, in response to a CPUC order, SCE constructed four of the five combustion turbine peaker plants, four of which were placed online in August 2007 to help meet peak customer demands and other system requirements. SCE anticipates submitting updated testimony in connection with its December 2007 cost recovery application to revise the total recorded costs as of late 2008, for the first four peaker plants, to approximately $263 million with additional projected costs for those peaker plants of approximately $1 million. In its cost recovery application, SCE proposed to continue tracking the capital costs of the fifth peaker plant according to the interim cost tracking mechanism that was previously approved by the CPUC for all five peaker projects while they were in construction. Additionally, SCE proposed to file a separate cost recovery application for the fifth peaker after it is installed or its final disposition is otherwise determined (see below for further discussion on the status of the fifth peaker plant). As of September 30, 2008, SCE has incurred capital costs of approximately $39 million for the fifth peaker. Several parties have filed protests or other filings in response to SCE s cost recovery application. SCE expects to fully recover its costs from these projects, but cannot predict the outcome of regulatory proceedings. SCE expects a CPUC decision on its cost recovery application in 2009.

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SCE has continued to pursue the construction of the fifth peaker plant. The required development permit was denied by the City of Oxnard in July 2007 and SCE appealed the denial to the California Coastal Commission. The Commission heard SCE s appeal on August 6, 2008, but did not reach a final decision. The SCE expects the matter to be heard again by April 2009.

Procurement of Renewable Resources

As discussed under the heading SCE: Regulatory Matters Current Regulatory Developments Procurement of Renewable Resources in the year-ended 2007 MD&A, 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, 2010.

SCE filed its latest compliance report in August 2008. Through the use of flexible compliance rules, SCE demonstrated full compliance for the procurement year 2007 and forecasted full compliance for the procurement years 2008 to 2020. It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

Under current CPUC decisions, potential penalties for SCE s inability to achieve its renewable procurement objectives 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.

FERC Refund Proceedings

As discussed under the heading SCE: Regulatory Matters Current Regulatory Developments FERC Refund Proceedings in the year-ended 2007 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 certain refunds realized by SCE, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

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 the second quarter of 2008 and in October 2008, SCE received distributions of approximately $25 million and $5 million, respectively, on its allowed bankruptcy claim. SCE has been advised that the Enron estate expects to conclude its liquidation in November of this year and therefore the amount or timing of additional distributions, if any, is uncertain.

In May 2008, SCE and a number of other parties entered into a settlement of the FERC refund proceeding issues with NEGT Energy Trading-Power, L.P. (NEGT) and a related party, both of which are debtors in a Chapter 11 proceeding pending in the Maryland bankruptcy court. Under the terms of the settlement, NEGT will provide refunds valued at $66 million, a portion of which will be paid in the form of an allowed, unsecured claim in the Chapter 11 bankruptcy proceeding. SCE s share of this amount is expected to be approximately $19 million. NEGT will also assign to SCE and the other parties to the settlement a corporate guarantee and surety bond that, subject to collection, will provide an additional $14 million. SCE s share of the $14 million is yet to be determined. The settlement was approved by the Maryland bankruptcy court on July 24, 2008 but remains subject to approval by the FERC.

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Investigation Regarding Performance Incentives Rewards

SCE was eligible under the CPUC-approved PBR mechanism to earn rewards or incur penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee safety reporting, and system reliability. SCE conducted investigations into its performance under the PBR mechanism and reported to the CPUC certain findings of misconduct and misreporting related to the first two components of the PBR program. Following SCE s reporting, the CPUC opened its own investigation of SCE s activities relative to the PBR mechanism.

CPUC Decision

On September 18, 2008, the CPUC adopted a decision in the first phase of its investigation into SCE s incentives claimed under the CPUC-approved PBR mechanism that allowed SCE to earn rewards or incur penalties for the period 1997 2003 based on its performance in comparison to CPUC-approved standards of customer satisfaction and employee safety reporting. The adopted decision required SCE to refund $28 million and $20 million related to customer satisfaction and employee safety reporting incentives, respectively; and further required SCE to forego claimed incentives of $20 million and $15 million related to customer satisfaction and employee safety reporting, respectively. The decision also required SCE to refund $33 million for employee bonuses and imposed a statutory penalty of $30 million. During the third quarter, SCE recorded a charge of $49 million, after-tax, reflected primarily in Other nonoperating deductions in the consolidated statements of income related to this decision.

System Reliability

In light of the problems uncovered with the components of the PBR mechanism discussed above, SCE conducted an investigation into the third PBR standard, system reliability, for the years 1997 2003. SCE received $8 million in reliability incentive awards for the period 1997 2000 and had applied for a reward of $5 million for 2001. For 2002, SCE s data indicated that it earned no reward and incurred no penalty. For 2003, based on the application of the PBR mechanism, SCE determined that it would incur a penalty of $3 million and accrued a charge for that amount in 2004. On February 28, 2005, SCE provided its final investigation report to the CPUC concluding that the reliability reporting system was working as intended. System reliability incentives will be addressed in the second phase of the CPUC s investigation. SCE served its opening testimony in the second phase in September 2007. In that testimony, SCE presented evidence that its PBR system reliability results were valid. The schedule for the second phase of the investigation has been deferred until November 21, 2008. SCE cannot predict the outcome of the second phase but does not expect a material financial statement impact.

Market Redesign and Technology Upgrade

As discussed under the heading SCE: Regulatory Matters Market Redesign and Technology Upgrade in the year ended 2007 MD&A, in early 2006, the ISO began a program to redesign and upgrade the wholesale energy market across ISO s controlled grid, known as the MRTU. The programs under the MRTU initiative are designed to implement market improvements to assure grid reliability, more efficient and cost-effective use of resources, and to create technology upgrades that would strengthen the entire ISO computer system. The CAISO has announced an implementation date of February 1, 2009, and expects to file a readiness application with the FERC in December 2008.

SCE: OTHER DEVELOPMENTS

Edison SmartConnect™

SCE s Edison SmartConnect™ project involves installing state-of-the-art smart meters in approximately 5.3 million households and small businesses through its service territory. The development of this advanced metering infrastructure is expected to be accomplished in three phases: the initial design phase to develop the new generation of advanced metering systems (Phase I), which was completed in 2006; the pre-deployment phase (Phase II) to field test and select Edison SmartConnect[tm] technologies, select the deployment vendor and finalize the Edison SmartConnect[tm] business case for full deployment, which was conducted during 2007; and the final deployment phase (Phase III), to deploy meters to all residential and small business customers under 200 kilowatts over a five-year period. SCE began deployment activities in 2008, expects to begin deployment of meters in 2009, and anticipates completion of the deployment in 2012. The total cost for this project, including Phase II pre-deployment, is estimated to be $1.7 billion of which $1.25 billion is estimated to be capitalized and included in utility rate base. The remaining book value for SCE s existing meters at September 30, 2008 is $396 million. SCE expects to recover the remaining book value of the existing meters over their remaining lives through its 2009 GRC application.

On July 26, 2007, the CPUC approved $45 million for Phase II of this project. The Phase II work was completed in December 2007. SCE filed its Phase III application on July 31, 2007, requesting CPUC authorization to deploy Edison SmartConnect[tm]. In March 2008, SCE reached a full settlement of the Phase III issues with the DRA and requested CPUC approval of the settlement. In September 2008, the CPUC approved the settlement, authorizing SCE to recover $1.63 billion in ratepayer funding for the Phase III deployment of Edison SmartConnect[tm].

Palo Verde Nuclear Generating Station Inspections

As discussed under the heading SCE: Other Developments Palo Verde Nuclear Generating Station Inspection in the year-ended 2007 MD&A, the NRC held three special inspections of Palo Verde, between March 2005 and February 2007. The combination of the results of the first and third special inspections caused the NRC to undertake an additional oversight inspection of Palo Verde. This additional inspection, known as a supplemental inspection, was completed in December 2007. In addition, Palo Verde was required to take additional corrective actions based on the outcome of completed surveys of its plant personnel and self-assessments of its programs and procedures. The NRC and APS defined and agreed to inspection and survey corrective actions that the NRC embodied in a Confirmatory Action Letter, which was issued in February 2008. APS is presently on track to complete the corrective actions required to close the Confirmatory Action Letter by mid-2009. Palo Verde operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE estimates that operation and maintenance costs will increase by approximately $23 million (in 2007 dollars) over the two year period 2008 2009, from 2007 recorded costs including overhead costs. SCE is unable to estimate how long SCE will continue to incur these costs. In the 2009 GRC, SCE requested recovery of, and two-way balancing account treatment for, Palo Verde operation and maintenance expenses including costs associated with these corrective actions. If approved, this would provide for recovery of these costs over the three-year GRC cycle (see SCE: Regulatory Matters Current Regulatory Developments 2009 General Rate Case Proceeding).

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.5 billion. SCE and other owners of San Onofre and 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 NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. Beginning October 29, 2008, the maximum deferred premium for each nuclear incident is approximately $118 million per reactor, but not more than approximately $18 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 at least once every five years beginning August 20, 2003. The most recent inflation adjustment took effect on October 29, 2008. Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 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

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subject to adjustment for inflation. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further revenue.

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 approximately $45 million per year. Insurance premiums are charged to operating expense.

Nuclear Decommissioning Trusts

SCE is collecting in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

Trust investments (at fair value) include:

In millions	Maturity Dates	September 30, 2008	December 31, 2007
Municipal bonds	2008 2044	**$ 564**	$ 561
Stocks		**1,672**	1,968
United States government issues	2008 2049	**318**	552
Corporate bonds	2008 2047	**267**	241
Short-term	2008 2009	**34**	56
Total		**$ 2,855**	$ 3,378

Note: Maturity dates as of September 30, 2008.

The following table sets forth a summary of changes in the fair value of the trust for the three- and nine-month periods ended September 30, 2008:

In millions	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
Balance at beginning of period	$ 3,152	$ 3,378
Realized losses net	(7)	(13)
Unrealized losses net	(240)	(452)
Other-than-temporary impairment	(49)	(121)
Earnings and other	(1)	63
Balance at September 30, 2008	**$ 2,855**	**$ 2,855**

The decrease in the trust investments was primarily due to net unrealized losses and other-than-temporary impairment resulting from a volatile stock market environment.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which effective January 2007, receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The next filing is in April 2009 for contribution changes in 2010. These contributions are determined based on an

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analysis of the current value of trusts assets and long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. The significant decrease recently experienced in the nuclear decommissioning trust assets, are expected to impact the CPUC established contributions for 2010. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates.

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.

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes, to fund business operations and to finance capital expenditures. Variances in actual financing costs compared to authorized financing costs either positively or negatively impact earnings. See SCE: Regulatory Matters Current Regulatory Developments 2008 Cost of Capital Proceeding for further discussion on SCE s recoverability of financing costs.

At September 30, 2008, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. At September 30, 2008, the fair market value of SCE s long-term debt (including long-term debt due within one year) was $5.57 billion, compared to a carrying value of $5.86 billion.

In July 2007, SCE entered into interest rate-locks to mitigate interest rate risk associated with future financings. Due to declining interest rates in late 2007, at December 31, 2007, these interest rate locks had unrealized losses of $33 million. In January and February 2008, SCE settled these interest rate-locks resulting in realized losses of $33 million. A related regulatory asset was recorded in this amount and SCE will amortize and recover this amount as interest expense associated with its series 2008A and 2008B financings issued in January and August 2008.

Commodity Price Risk

As discussed in the year-ended 2007 MD&A, SCE is exposed to commodity price risk associated with its purchases for additional capacity and ancillary services to meet its peak energy requirements as well as exposure to natural gas prices associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including SCE s Mountainview plant.

SCE has an active hedging program in place to minimize ratepayer exposure to spot-market price spikes; however, to the extent that SCE does not mitigate the exposure to commodity price risk, the unhedged portion is subject to the risks and benefits of spot-market price movements, which are ultimately passed-through to ratepayers.

To mitigate SCE s exposure to spot-market prices, SCE enters into energy options, tolling arrangements, forward physical contracts, and transmission congestion rights (firm transmission rights and CRRs). SCE also 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.

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In September 2007, the ISO allocated CRRs for the period March 2008 through December 2017 to SCE which will entitle SCE to receive (or pay) the value of transmission congestion between specific locations. These rights will act as an economic hedge against transmission congestion costs in the MRTU environment which was expected to be operational March 31, 2008, but was delayed. The CRRs meet the definition of a derivative under SFAS No. 133. In accordance with SFAS No. 157, SCE recognized the CRRs at a zero fair value due to liquidity reserves. Liquidity reserves against CRRs fair values were provided since there were no quoted long-term market prices for the CRRs allocated to SCE. Although an auction was held in December 2007, the auction results did not provide sufficient evidence of long-term market prices.

During the first quarter of 2008, the ISO held an auction for firm transmission rights. SCE participated in the ISO auction and paid $62 million to secure firm transmission rights for the period April 2008 through March 2009. The firm transmission rights will be replaced with CRRs in the MRTU environment. SCE recognized the firm transmission rights at fair value. SCE anticipates amounts paid for firm transmission rights that will no longer be valid in the MRTU environment will be refunded to SCE and has recognized this amount as a receivable from the ISO.

Any future fair value changes, given a MRTU market, will be recorded in purchased-power expense and offset through the provision for regulatory adjustments clauses as the CPUC allows these costs to be recovered from or refunded to customers through a regulatory balancing account mechanism. As a result, fair value changes are not expected to affect earnings.

SCE records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. Certain derivative instruments do not meet the normal purchases and sales exception because demand variations and CPUC mandated resource adequacy requirements may result in physical delivery of excess energy that may not be in quantities that are expected to be used over a reasonable period in the normal course of business and may then be resold into the market. In addition, certain contracts do not meet the definition of clearly and closely related under SFAS No. 133 since pricing for certain renewable contracts is based on an unrelated commodity. 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 net; therefore, fair value changes do not affect earnings. Hedge accounting is not used for these transactions due to this regulatory accounting treatment.

The following table summarizes the fair values of outstanding derivative financial instruments used at SCE to mitigate its exposure to spot market prices:

	September 30, 2008		**December 31, 2007**	
In millions	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Energy options	**$ 15**	**$ 39**	$ 6	$ 49
Firm transmission rights	**34**	**2**	22	
Forward physicals (power) and tolling arrangements	**4**	**7**	7	8
Gas options, swaps and forward arrangements	**85**	**166**	46	22
Netting and collateral		**(52)**		(2)
Total	**$ 138**	**$ 162**	$ 81	$ 77

SCE implemented SFAS No. 157 during the first quarter of 2008. SCE s assets and liabilities carried at fair value primarily consist of derivatives, nuclear decommissioning trust investment and money market funds. Derivative contracts primarily relate to power and gas and include contracts for forward physical sales and purchases, options and forward price swaps which settle only on a financial basis (including futures contracts). Derivative contracts can be exchange traded or over-the-counter traded. If quoted market prices are not available, internally maintained standardized or industry accepted models are used to determine the fair value. The models are updated with spot prices, forward prices, volatilities and interest rates from regularly published and widely distributed independent sources. Under SFAS No. 157, when actual market prices, or relevant observable inputs are not available it is

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appropriate to use unobservable inputs which reflect management assumptions, including extrapolating limited short-term observable data and developing correlations between liquid and non-liquid trading hubs.

Derivatives that are exchange traded in active markets for identical assets or liabilities are classified as Level 1. The fair value of derivative contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors.

Level 2 primarily consists of natural gas swap and natural gas physical trade derivatives for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange.

Level 3 includes the majority of SCE s derivatives, including over-the-counter options, bilateral contracts, and capacity and QF contracts. The fair value of these derivatives is determined using uncorroborated non-binding broker quotes (from one or several brokers) and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Fair values that are obtained from several brokers are compared against each other for reasonableness. Level 3 also includes derivatives that trade infrequently (such as firm transmission rights and CRRs in the California market and over-the-counter derivatives at illiquid locations), derivatives with counterparties that have significant non-performance risks and long-term power agreements. For illiquid firm transmission rights, SCE reviews objective criteria related to system congestion on a quarterly basis and other underlying drivers and adjusts fair value when SCE concludes a change in objective criteria would result in a new valuation that better reflects the fair value. Changes in fair values are based on hypothetical sale of illiquid positions. For illiquid long-term power agreements, fair value is based upon a discounting of future electricity prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit risk and market liquidity. Changes in fair value are based on changes to forward market prices, including forecasted prices for illiquid forward periods.

Firm transmission rights, capacity and QF contracts are in inactive markets. CRRs do not yet have a market. In circumstances where SCE cannot verify fair value with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. As markets continue to develop and more pricing information becomes available, SCE continues to assess valuation methodologies used to determine fair value.

The SCE nuclear decommissioning trust investments include equity securities, U.S. treasury securities and other fixed-income securities. Equity and treasury securities are classified as Level 1 as fair value is determined by observable market prices in active or highly liquid and transparent markets. The remaining fixed-income securities are classified as Level 2. The fair value of these financial instruments is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information.

SCE s investment policies place limitations on the types and investment grade ratings of the securities that may be held by the nuclear decommissioning trust fund. These policies restrict the trust fund from holding alternative investments and limit the trust funds exposures to investments in highly illiquid markets. With respect to equity securities, the trustee obtains prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which SCE is able to independently corroborate. Regarding fixed income securities, the trustee receives multiple prices from pricing services, which enable cross-provider validations by the trustee in addition to unusual daily movement checks. A primary price source is identified based on asset type, class or issue for each security. The trustee monitors prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the trustee challenges an assigned price and determines that another price source is considered to be preferable. Additionally, SCE corroborates the fair values of securities by comparison to other market-based price sources obtained by SCE s investment managers.

The amount of SCE s level 3 derivative assets and liabilities measured using significant unobservable inputs as a percentage of the total derivative assets and total derivative liabilities (excluding netting and collateral) measured at fair value were 98% and 53%, respectively. During the first nine months of 2008, the level 3 fair values decreased as a result of changes in realized and unrealized losses.

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SCE recorded net realized and unrealized losses of $603 million and $138 million for the three months ended September 30, 2008 and 2007, respectively. SCE recorded net realized and unrealized losses of $92 million and $97 million for the nine months ended September 30, 2008 and 2007, respectively. The changes in net realized and unrealized losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008, compared to the same periods in 2007. Due to expected recovery through regulatory mechanisms unrealized gains and losses may temporarily affect cash flows, but are not expected to affect earnings.

Credit Risk

As part of SCE s procurement activities, SCE contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. If a counterparty were to default on its contractual obligations, SCE could be exposed to potentially volatile spot markets for buying replacement power or selling excess power. In addition, SCE would be exposed to the risk of non-payment of accounts receivable, primarily related to sales of excess energy and realized gains on derivative instruments.

To manage credit risk, SCE 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. SCE measures, monitors and mitigates credit risk to the extent possible. SCE 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. SCE s risk management committee regularly reviews and evaluates procurement credit exposure and approves credit limits for transacting with 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. However, all of the contracts that SCE has entered into with counterparties are either entered into under SCE s short-term or long-term procurement plan which has been approved by the CPUC, or the contracts are approved by the CPUC before becoming effective. As a result of regulatory recovery mechanisms, losses from non-performance are not expected to affect earnings, but may temporarily affect cash flows. SCE anticipates future delivery of energy by counterparties, but given the current market condition, SCE cannot predict whether the counterparties will be able to continue operations and deliver energy under the contractual agreements.

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The credit risk exposure from counterparties for power and gas trading activities is measured as the sum of net accounts receivable (accounts receivable less accounts payable) and the current fair value of net derivative assets reflected on the balance sheet. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE s credit risk exposure from counterparties is based on a net exposure under these arrangements. At September 30, 2008, the amount of balance sheet exposure as described above, broken down by the credit ratings of SCE s counterparties, was as follows:

	September 30, 2008		
In millions	**Exposure**[2]	**Collateral**	**Net Exposure**
S&P Credit Rating[1]			
A or higher	$ 3	$	$ 3
A-	36		36
BBB+			
BBB			
BBB-			
Below investment grade and not rated			
Total	$ 39	$	$ 39

(1) SCE assigns a credit rating based on the lower of a counterparty s S&P or Moody s rating. For ease of reference, the above table uses the S&P classifications to summarize risk, but reflects the lower of the two credit ratings.

(2) Exposure excludes amounts related to contracts classified as normal purchase and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheet, except for any related net accounts receivable.

The credit risk exposure set forth in the above table is comprised of $5 million of net accounts receivable and payables and $34 million representing the fair value of derivative contracts.

Included in the table above are exposures to counterparties with credit ratings of A- or above. Due to recent developments in the financial markets, the credit ratings may not be reflective of the related credit risk. The CAISO comprises 83% of the total net exposure above and is mainly related to purchases of firm transmission rights (see Commodity Price Risk for further information).

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EDISON MISSION GROUP

EMG: LIQUIDITY

Liquidity

At September 30, 2008, EMG and its subsidiaries had cash and cash equivalents and short-term investments of $1.9 billion. EMG s subsidiaries had a total of $45 million of available borrowing capacity under their credit facilities. EME had a total of $23 million of available borrowing capacity under its $600 million credit facility, and Midwest Generation had a total of $22 million of available borrowing capacity under its $500 million working capital facility. EMG s consolidated debt at September 30, 2008 was $4.83 billion. In addition, EME s subsidiaries had $3.6 billion of long-term lease obligations related to the sale-leaseback transactions that are due over periods ranging up to 26 years.

The following table summarizes the status of the EME and Midwest Generation credit facilities at September 30, 2008:

In millions	EME	Midwest Generation
Commitment	$ 600	$ 500
Less: Commitment from Lehman Brothers subsidiary	(36)	
	564	500
Outstanding borrowings	(423)	(475)
Outstanding letters of credit	(118)	(3)
Amount available	$ 23	$ 22

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Commercial Paper Inc., is one of the lenders in EME s credit agreement representing a commitment of $36 million. In September 2008, Lehman Commercial Paper declined requests for funding under EME s credit agreement. Another subsidiary of Lehman Brothers Holdings, Lehman Brothers Commercial Bank, Inc., is one of the lenders in the Midwest Generation working capital facility. This subsidiary fully funded $42 million of Midwest Generation s borrowing requests, which remains outstanding. At September 30, 2008, Lehman Brothers Commercial Bank, Inc. s share of the amount available to draw under the Midwest Generation working capital facility was $2 million.

Access to the capital markets has become subject to increased uncertainty due to the financial market and economic conditions discussed in Edison International: Current Developments Financial Markets and Economic Conditions. Accordingly, EME s liquidity is currently comprised of cash on hand and cash flow generated from operations. Pending recovery of the capital markets, EME intends to preserve capital by focusing on a more selective growth strategy (primarily completion of projects under construction, including the Big Sky project in Illinois, and development of sites for future renewable projects deploying current turbine commitments), and using its cash and future cash flow to meet its existing contractual commitments. Moreover, disruption in the financial markets appears to have reduced trading activity in power markets which may affect the level and duration of future hedging activity and potentially increase the volatility of earnings. Long-term disruption in the capital markets could adversely affect EME s business plans and potentially impact EME s financial position.

Business Development

EME has undertaken a number of activities in 2008 with respect to wind projects, including the following:

Completed the acquisition of a 240 MW planned wind project in Illinois, referred to as the Big Sky project with payments tied to various milestones. In addition, EME has commenced pre-construction activities for equipment purchases, site development and interconnection activities. Release of the project for full construction is pending a decision on selection of turbines. For further discussion refer to Commitments, Guarantees and Indemnities Turbine Commitments. The total commitments at September 30, 2008, excluding turbines, were approximately $99 million, including the project acquisition costs. Upon completion, the project plans to sell electricity into the PJM market as a merchant generator or to local utilities under power sales contracts.

Acquired and/or completed development and commenced construction with completion scheduled for 2008 of the 19 MW Buffalo Bear wind project located in Oklahoma and the 80 MW Elkhorn Ridge project located in Nebraska, and for 2009 of the 100 MW High Lonesome wind project located in New Mexico. The estimated capital cost of these projects, excluding capitalized interest, is expected to be approximately $338 million. EME owns 66.67% of the Elkhorn Ridge wind project and 100% of the Buffalo Bear wind project and the High Lonesome wind project. Each project will, after its completion, sell electricity pursuant to power sales agreements.

Completed construction and commenced operations of the 29 MW Forward wind project located in Pennsylvania, the 20 MW Odin wind project located in Minnesota, Phase I (80 MW) of the Goat Mountain wind project in Texas, the 19 MW Spanish Fork wind project located in Utah, the 61 MW Mountain Wind I and the 80 MW Mountain Wind II projects, both located in Wyoming.

In addition, EME submitted bids in competitive solicitations to supply power from solar projects under development in California and has had a number of its proposals short-listed by utilities. Initial site and equipment selection have been completed along with preliminary economic feasibility studies. Further project development activities are underway to obtain transmission interconnection, control of sites, and construction costs estimates, as well as the negotiation of power sales agreements. To support these development activities, EME entered into an agreement with First Solar Electric, LLC to provide design, engineering, procurement, and construction services for solar projects for identified customers, subject to the satisfaction of certain contingencies and entering into definitive agreements for such services for each project.

Capital Expenditures

At September 30, 2008, the estimated capital expenditures through 2010 by EME s subsidiaries related to existing projects, corporate activities and turbine commitments were as follows:

In millions	October through December 2008	2009	2010
Illinois Plants			
Plant capital expenditures	**$ 32**	$ 65	$ 106
Environmental expenditures	**24**	103	263
Homer City Facilities			
Plant capital expenditures	**11**	29	55
Environmental expenditures	**3**	8	14
New Projects			
Projects under construction	**128**	24	
Turbine commitments	**66**	794	260
Other capital expenditures	**14**	16	11
Total	**$ 278**	**$ 1,039**	**$ 709**

Expenditures for Existing Projects

Plant capital expenditures relate to non-environmental projects such as upgrades to boiler and turbine controls, railroad interconnection, replacement of major boiler components, mill inerting projects and ash site disposal development. Environmental expenditures relate to environmental projects such as mercury emission monitoring and control at the Homer City facilities and various projects at the Illinois plants to achieve specified emissions reductions such as installation of mercury controls. For further discussion regarding these and possible additional capital expenditures, including environmental control equipment at the Homer City facilities, refer to Edison International: Management s Overview, and Other Developments Environmental Matters Air Quality Regulation Clean Air Interstate Rule Illinois, and Other Developments Environmental Matters Air Quality Regulation Mercury Regulation of in the year ended December 31, 2007 MD&A.

Expenditures for New Projects

EME expects to make substantial investments in new projects during the next several years. At September 30, 2008, EME had committed to purchase turbines (as reflected in the above table of capital expenditures) for wind projects that aggregate 942 MW. The turbine commitments generally represent approximately two-thirds of the total capital costs of EME s wind projects. As of September 30, 2008, EME had a development pipeline of potential wind projects with projected installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. Completion of development of a wind project may take a number of years due to factors that include local permit requirements, willingness of local utilities to purchase renewable power at sufficient prices to earn an appropriate rate of return, and availability and prices of equipment. Furthermore, successful completion of a wind project is dependent upon obtaining permits, an interconnection agreement(s) or other agreements necessary to support an investment. There is no assurance that each project included in the development pipeline currently or added in the future will be successfully completed.

In addition, a subsidiary of EME was awarded through a competitive bidding process a ten-year power sales contract with SCE for the output of the Walnut Creek project. During the second quarter of 2008, EME and its subsidiary entered into an agreement to purchase major equipment for the project included in turbine commitments in the above table. Subject to the resolution of the legal challenges discussed below and availability of financing, EME intends to construct the project in advance of the 2013 start date in the power sales contract with total installed costs, excluding interest during construction, estimated in the range of $500 million to $600 million.

Due to the lack of available particulate matter (PM10) and SO_2 emission credits in the air basins regulated by SCAQMD, and the difficulty of creating new ones, Walnut Creek is unable to acquire the emission credits that it needs prior to beginning construction until favorable resolution of the legal challenges to the SCAQMD s New Source Review accounts (which include the Priority Reserve of emissions credits that were made available for new generation power projects). See Other Developments Priority Reserve Legal Challenges for more information on the legal challenges.

Credit Ratings

Overview

Credit ratings for EMG s direct and indirect subsidiaries at September 30, 2008, were as follows:

	Moody s Rating	S&P Rating	Fitch Rating
EME	B1	BB-	BB-
Midwest Generation	Baa3	BB+	BBB-
EMMT	Not Rated	BB-	Not Rated
Edison Capital (Edison Funding)	Ba1	BB+	Not Rated

In August 2008, Moody s placed Edison Funding s senior notes under review for a possible rating downgrade. EMG 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. EMG 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.

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

Credit Rating of EMMT

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

Margin, Collateral Deposits and Other Credit Support for Energy Contracts

To reduce its exposure to market risk, EME hedges a portion of its electricity sales through EMMT, an EME subsidiary engaged in the power marketing and trading business. In connection with entering into contracts, EMMT may be required to support its risk of nonperformance through parent guarantees, margining or other credit support. EME has entered into guarantees in support of EMMT s hedging and trading activities; however, because the credit ratings of EMMT and EME are below investment grade, EME has historically also provided collateral in the form of cash and letters of credit for the benefit of counterparties related to the net of accounts payable, accounts receivable, unrealized losses, and unrealized gains in connection with these hedging and trading activities. At September 30, 2008, EMMT had deposited $81 million in cash with clearing brokers in support of futures contracts and had deposited $66 million in cash with counterparties in support of forward energy and congestion contracts. In addition, EME had issued letters of credit of $4 million in support of commodity contracts at September 30, 2008.

Future cash collateral requirements may be higher than the margin and collateral requirements at September 30, 2008, if wholesale energy prices increase or the amount hedged increases. EME estimates that margin and collateral requirements for energy and congestion contracts outstanding as of September 30, 2008 could increase by approximately $90 million over the remaining life of the contracts using a 95% confidence level. Certain EMMT hedge contracts do not require margining, but contain provisions that require EME or Midwest Generation to comply with the terms and conditions of their credit facilities. The credit facilities contain financial covenants which are described further in Covenants in Major Financings. Furthermore, the hedge contracts include provisions relating to a change in control or material adverse effect resulting from amendments or modifications to the related credit facility. Failure by EME or Midwest Generation to comply with these provisions would result in a termination event under the hedge contracts, enabling the counterparties to terminate and liquidate all outstanding transactions and demand immediate payment of amounts owed to them. EMMT also has hedge contracts that do not require margining, but contain the right of each party to request additional credit support in the form of adequate assurance of performance in the case of an adverse development affecting the other party. The aggregate fair value of hedge contracts with credit-risk related contingent features was a net asset at September 30, 2008 and, accordingly, the contingent features described above do not currently have a liquidity exposure. Future increases in power prices could expose EME or Midwest Generation to termination payments or posting additional collateral under the contingent features described above.

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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, 2008, Midwest Generation had available $22 million of borrowing capacity under this credit facility. As of September 30, 2008, Midwest Generation had $29 million in loans receivable from EMMT for margin advances. In addition, EME has cash on hand and $23 million of borrowing capacity available under a $600 million working capital facility to provide credit support to subsidiaries.

Covenants 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.

EME s credit facility contains financial covenants which require EME to maintain a minimum interest coverage ratio and a maximum corporate debt-to-corporate capital ratio as such terms are defined in the credit facility. The key ratios at September 30, 2008 or for the 12 months ended September 30, 2008 are as follows:

Financial Ratio	Covenant	Actual
Interest Coverage Ratio	Not less than 1.2 to 1	1.68 to 1
Corporate Debt to Corporate Capital Ratio	Not more than 0.75 to 1	0.60 to 1

Key Ratios of EMG s Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME s principal subsidiaries required by financing arrangements at September 30, 2008 or for the 12 months ended September 30, 2008:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Illinois plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.28 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.95 to 1

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, 2008.

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 EMG: Liquidity Dividend Restrictions in Major Financings in the year-ended 2007 MD&A.

EMG: OTHER DEVELOPMENTS

PJM Matters

On April 4, 2008, the FERC issued an order rejecting PJM s request to revise its RPM to reflect PJM s claimed rise in its CONE values. CONE is one of the two components used by PJM to determine its Variable Resource Requirement curve for the RPM auction. PJM also proposed to add a new section to its tariff permitting PJM to unilaterally request a CONE increase for use in its May 2008 RPM auction for the 2011/2012 delivery year. In rejecting the proposal, the FERC found that PJM had not met timing provisions in its existing tariff to provide sufficient time for stakeholder review of the analysis and advance planning and that it had also failed to establish that its proposal to revise that provision was necessary on a one-time emergency basis to ensure reliable service.

The effect of FERC s actions on future RPM auctions cannot be determined at this time. The CONE as established for the May 2008 RPM auction for the 2011/2012 delivery year is lower than the PJM request.

RPM Buyers Complaint

On May 30, 2008, a group of entities referring to themselves as the RPM Buyers filed a complaint at the FERC asking that PJM s RPM, as implemented through the transitional base residual auctions establishing capacity payments for the period from June 1, 2008 through May 31, 2011, be found to have produced unjust and unreasonable capacity prices. The RPM Buyers alleged that the absence of price discipline provided by new capacity resources, together with the ability of existing resources to withhold some capacity within the RPM rules, produced capacity prices in the transition period that are not comparable to those that would have been produced in a competitive market or determined under cost-based regulation, and have requested that the FERC order refunds based on that difference.

On July 10, 2008, EME responded to the RPM Buyers complaint asking that it be dismissed based upon various legal precedents. A number of other parties, including PJM, also responded to the RPM Buyers complaint asking that it be dismissed. On September 19, 2008, the FERC dismissed the RPM Buyers compliant, finding that the RPM Buyers had failed to allege or prove that any party violated PJM s tariff and market rules, and that the prices determined during the transition period were determined in accordance with PJM s FERC-approved tariff. On October 20, 2008, the RPM Buyers requested rehearing of the FERC s order dismissing their compliant. This matter is currently pending before the FERC. EME cannot predict the outcome of this matter.

EME Homer City New Source Review Notice of Violation

On June 12, 2008, EME Homer City received an NOV from the US EPA alleging that, beginning in 1988, EME Homer City (or former owners of the Homer City facilities) performed repair or replacement projects at Homer City Units 1 and 2 without first obtaining construction permits as required by the Prevention of Significant Deterioration requirements of the Clean Air Act. The US EPA also alleges that EME Homer City has failed to file timely and complete Title V permits. EME Homer City has met with the US EPA and has expressed its intent to explore the possibility of a settlement. If no settlement is reached and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. EME Homer City is investigating the NOV claims and is developing a litigation strategy. EME Homer City cannot predict at this time what effect this matter may have on its facilities, its results of operations, financial position or cash flows.

EME Homer City has sought indemnification for liability and defense costs associated with the NOV from the sellers under the asset purchase agreement pursuant to which EME Homer City acquired the Homer City facilities. The sellers responded by denying the indemnity obligation, but accepting the defense of the claims.

EME Homer City notified the sale-leaseback owner participants of the Homer City facilities of the NOV under the operative indemnity provisions of the sale-leaseback documents. The owner participants of the Homer City facilities, in turn, have sought indemnification and defense from EME Homer City for costs and liability associated with the EME Homer City NOV. EME Homer City responded by undertaking the indemnity obligation and defense of the claims.

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EMG: MARKET RISK EXPOSURES

Introduction

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

Commodity Price Risk

Introduction

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

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

EME uses earnings at risk to identify, measure, monitor and control its overall market risk exposure with respect to hedge positions at the Illinois plants, the Homer City facilities, and the merchant wind projects, and value at risk to identify, measure, monitor and control its overall risk exposure in respect of its trading positions. The use of these measures allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify the risk factors. Value at risk measures the possible loss, and earnings at risk measures the potential change in value of an asset or position, in each case over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of these measures and reliance on a single type of risk measurement tool, EME supplements these approaches with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss triggers and counterparty credit exposure limits.

Hedging Strategy

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

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

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

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

Energy Price Risk Affecting Sales from the Illinois Plants

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

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

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

The following table depicts the average historical market prices for energy per megawatt-hour during the first nine months of 2008 and 2007.

	24-Hour Northern Illinois Hub Historical Energy Prices[1]	
	2008	**2007**
January	$ 47.09	$ 35.75
February	54.46	56.64
March	58.58	42.04
April	53.87	48.91
May	44.49	44.49
June	56.06	39.76
July	63.79	43.40
August	52.66	57.97
September	43.08	39.68
Nine-Month Average	$ 52.68	$ 45.40

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

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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, 2008:

	24-Hour Northern Illinois Hub Forward Energy Prices[1]	
2008		
October	$	43.27
November		39.76
December		43.21
2009 Calendar strip[2]	$	48.02
2010 Calendar strip[2]	$	48.52

(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.

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The following table summarizes Midwest Generation s hedge position at September 30, 2008:

	2008		2009		2010		2011	
	GWh	Average price/ MWh	GWh	Average price/ MWh	GWh	Average price/ MWh	GWh	Average price/ MWh
Energy Only Contracts[1][2]								
Northern Illinois Hub AEP/Dayton Hub	**2,765**	**$ 61.35**	9,945	$ 65.42	6,534	$ 68.62	611	$ 76.40
Load Requirements Services Contracts[3][4]								
Northern Illinois Hub	**1,015**	**63.65**	1,571	63.65				
Total estimated GWh	**3,780**		11,516		6,534		611	

(1) The energy only contracts include forward contracts for the sale of power and futures contracts during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge positions at September 30, 2008 are not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

(2) The energy only contracts exclude power contracts held with Lehman Brothers Commodity Services, Inc. totaling 1,434 GWh for 2009 and 1,428 GWh for 2010 which were suspended at September 30, 2008 and subsequently terminated in October 2008. For further discussion, see Accounting for Energy Contracts.

(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 GWh have been forecast based on historical patterns and on assumptions regarding the factors that may affect retail loads in the future. The actual load will vary from that used for the above estimate, and the amount of variation may be material.

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

Energy Price Risk Affecting Sales from the Homer City Facilities

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

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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 (EME Homer City s primary trading hub) during the first nine months of 2008 and 2007:

	Historical Energy Prices[1]			
			24-Hour PJM	
	Homer City		West Hub	
	2008	2007	2008	2007
January	$ 54.32	$ 40.30	$ 66.80	$ 44.63
February	61.74	64.27	68.29	73.93
March	65.37	55.00	70.48	61.02
April	61.99	52.42	69.12	58.74
May	49.37	48.12	59.84	53.89
June	78.72	45.88	98.50	60.19
July	72.39	48.23	91.80	58.89
August	60.16	55.44	73.91	71.00
September	52.33	48.90	66.04	60.14
Nine-Month Average	$ 61.82	$ 50.95	$ 73.86	$ 60.27

(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, 2008:

	24-Hour PJM West Hub Forward Energy Prices[1]
2008	
October	$ 57.79
November	55.32
December	59.53
2009 Calendar strip[2]	$ 66.23
2010 Calendar strip[2]	$ 68.31

(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.

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The following table summarizes EME Homer City s hedge position at September 30, 2008:

	2008	2009	2010
GWh	1,708	4,096	2,654
Average price/MWh[(1)]	$ 60.90	$ 82.84	$ 90.52

(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, 2008 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

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

Capacity Price Risk

On June 1, 2007, PJM implemented the RPM for capacity. The purpose of the RPM is to provide a long-term pricing signal for capacity resources. The RPM provides a mechanism for PJM to satisfy the region s need for generation capacity, the cost of which is allocated to load-serving entities through a locational reliability charge.

The following table summarizes the status of capacity sales for Midwest Generation and EME Homer City at September 30, 2008:

	Fixed Price Capacity Sales					
	Through RPM Auction, Net		Non-unit Specific Capacity Sales		Variable Capacity Sales	
	MW	Price per MW-day	MW	Price per MW-day	MW	Price per MW-day
October 1, 2008 to May 31, 2009						
Midwest Generation	2,954	$ 122.42(1)	880	$ 64.35		
EME Homer City	820	111.92			905	$ 62.22(2)
June 1, 2009 to May 31, 2010						
Midwest Generation	4,614	102.04	715	71.46		
EME Homer City	1,670	191.32				
June 1, 2010 to May 31, 2011						
Midwest Generation	4,929	174.29				
EME Homer City	1,813	174.29				
June 1, 2011 to May 31, 2012						
Midwest Generation	4,582	110.00				
EME Homer City	1,771	110.00				

(1) The original price of $111.92 was affected by Midwest Generation s participation in a supplemental RPM auction during the first quarter of 2008 which resulted in purchasing certain capacity amounts at a price of $10 per MW-day, thereby reducing the aggregate forward capacity sales for this period and increasing the effective capacity price to $122.42.

(2) Actual contract price is a function of NYISO capacity auction clearing prices for October 2008 and forward over-the-counter NYISO capacity prices on September 30, 2008 for November 2008 through May 2009.

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

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

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

Basis Risk

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

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

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

Under PJM s market design, locational marginal pricing, which establishes market prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, can cause the price of a specific delivery point to be higher or lower relative to other locations depending on how the point is affected by transmission constraints. Effective June 1, 2007, PJM implemented marginal losses which adjust the algorithm that calculates locational marginal prices to include a component for marginal transmission losses in addition to the component included for congestion. To the extent that, on the settlement date of a hedge contract, spot prices at the relevant busbar are lower than spot prices at the settlement point, the proceeds actually realized from the related hedge contract are effectively reduced by the difference. This is referred to as basis risk. During the nine months ended September 30, 2008, transmission congestion in PJM has resulted in prices at the Homer City busbar being lower than those at the PJM West Hub by an average of 16%, compared to 15% during the nine months ended September 30, 2007. The monthly average difference during the 12 months ended September 30, 2008 ranged from 7% to 21%. In contrast to the Homer City facilities, during the past 12 months, the prices at the Northern Illinois Hub were substantially the same as those at the individual busbars of the Illinois plants, although the implementation of marginal losses on June 1, 2007 has lowered energy prices at the Illinois plants busbars.

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

Coal and Transportation Price Risk

The Illinois plants and the Homer City facilities purchase coal primarily obtained from the Southern PRB of Wyoming and from mines located near the facilities in Pennsylvania, respectively. Coal purchases are made under a variety of supply agreements extending through 2011. The following table summarizes the amount of coal under contract at September 30, 2008 for the remainder of 2008 and the following three years.

	Amount of Coal Under Contract in Millions of Tons(1)			
	October through December 2008	**2009**	**2010**	**2011**
Illinois Plants	5.6	12.8	11.7	
Homer City facilities(2)	1.9	4.5	0.4	0.3

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

(2) At September 30, 2008, there are options to purchase additional coal of 0.3 million tons in 2009, 1.9 million tons in 2010 and 1.4 million tons in 2011.

EME is subject to price risk for purchases of coal that are not under contract. Prices of Northern Appalachian coal, which are related to the price of coal purchased for the Homer City facilities, increased substantially during 2008 from 2007 year-end prices. The price of Northern Appalachian coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content) increased to $143 per ton at October 3, 2008 from $55.25 per ton at December 21, 2007, as reported by the Energy Information Administration. Prices of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per MMBtu sulfur content) purchased for the Illinois plants increased during 2008 from 2007 year-end prices. The price of PRB coal increased to $14.50 per ton at October 3, 2008 from $11.50 per ton at December 21, 2007, as reported by the Energy Information Administration. The 2008 increase in North Appalachian coal prices were primarily attributable to: 1) increased international and Atlantic basin coal demand, 2) port and rail infrastructure problems and monsoon flooding in Australia, 3) a record cold winter in China, and 4) an energy crisis in South Africa.

EME has contractual agreements for the transport of coal to its facilities. The primary contract is with Union Pacific Railroad (and various delivering carriers), which extends through 2011. EME is exposed to price risk related to higher transportation rates after the expiration of its existing transportation contracts. Current transportation rates for PRB coal are higher than the existing rates under contract (transportation costs are more than 50% of the delivered cost of PRB coal to the Illinois plants).

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO_2 allowances, and Illinois and Pennsylvania regulations implemented the federal NO_X SIP Call requirement. As part of the acquisition of the Illinois plants and the Homer City facilities, EME obtained the rights to the emission allowances that have been or are allocated to these plants. EME purchases (or sells) emission allowances based on the amounts required for actual generation in excess of (or less than) the amounts allocated under these programs.

The average price of purchased SO_2 allowances decreased to $316 per ton during the first nine months of 2008 from $521 per ton during 2007. The price of SO_2 allowances, determined by obtaining broker quotes and information from other public sources, was $155 per ton as of September 30, 2008.

For an updated discussion of environmental regulations related to emissions, see Other Developments Environmental Matters Air Quality Regulation Clean Air Interstate Rule.

Accounting for Energy Contracts

EME uses a number of energy contracts to manage exposure from changes in the price of electricity, including forward sales and purchases of physical power and forward price swaps which settle only on a financial basis (including futures contracts). EME follows SFAS No. 133, and under this Standard these energy contracts are generally defined as derivative financial instruments. Importantly, SFAS No. 133 requires changes in the fair value of each derivative financial instrument to be recognized in earnings at the end of each accounting period unless the instrument qualifies for hedge accounting under the terms of SFAS No. 133. For derivatives that do qualify for cash flow hedge accounting, changes in their fair value are recognized in other comprehensive income until the hedged item settles and is recognized in earnings. However, the ineffective portion of a derivative that qualifies for cash flow hedge accounting is recognized currently in earnings. For further discussion of derivative financial instruments, refer to Critical Accounting Estimates and Policies Derivative Financial Instruments and Hedging Activities in the year-ended December 31, 2007 MD&A.

SFAS No. 133 affects the timing of income recognition, but has no effect on cash flow. To the extent that income varies under SFAS No. 133 from accrual accounting (i.e., revenue recognition based on settlement of transactions), EME records unrealized gains or losses. EME classifies unrealized gains and losses from energy contracts as part of operating revenues. The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows. The following table summarizes unrealized gains (losses) from non-trading activities for the third quarters of 2008 and 2007 and nine months ended September 30, 2008 and 2007:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2008**	2007	**2008**	2007
Illinois Plants				
Non-qualifying hedges	**$ (24)**	$	**$ (22)**	$ (18)
Ineffective portion of cash flow hedges	**17**	(8)	**7**	(8)
Homer City				
Non-qualifying hedges	**(2)**	(1)		
Ineffective portion of cash flow hedges	**16**	(2)	**7**	(5)
Total unrealized gains (losses)	**$ 7**	$ (11)	**$ (8)**	$ (31)

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. EME had power contracts with Lehman Brothers Commodity Services, Inc., a subsidiary of Lehman Brothers Holdings, for Midwest Generation for 2009 and 2010. The obligations of Lehman Brothers Commodity Services under the power contracts are guaranteed by Lehman Brothers Holdings. These contracts qualified as cash flow hedges under SFAS No. 133 until EME designated the power contracts as such, effective September 12, 2008 when it determined that it was no longer probable that performance would occur. The amount recorded in accumulated comprehensive income (loss) related to the effective portion of the hedges was $24 million pre-tax on this date. Since the power contracts are no longer being accounted for as cash flow hedges under SFAS No. 133, the subsequent change in fair value was recorded as an unrealized loss during the third quarter of 2008. Under SFAS No. 133, the pre-tax amount recorded in accumulated other comprehensive income (loss) will be reclassified to operating revenues based on the original forecasted transactions in 2009 ($15 million) and 2010 ($9 million), unless it becomes probable that the forecasted transactions will no longer occur.

During the three months ended September 30, 2008, unrealized gains resulting from the ineffective portion of cash flow hedges resulted primarily from a change in the fair value of derivatives from a net derivative liability position at June 30, 2008 to a net derivative asset position at September 30, 2008. SFAS No. 133 limits the amounts recorded in accumulated other comprehensive income to the lesser of the change in the fair value of the derivative or the hedge item (forecasted transaction).

At September 30, 2008, unrealized losses of $47 million (including the unrealized losses described above related to Lehman Brothers Commodity Services) were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to subsequent periods ($8 million for the remainder of 2008, $21 million for 2009, and $18 million for 2010).

Fair Value of Financial Instruments

Non-Trading Derivative Financial Instruments

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

In millions	September 30, 2008	December 31, 2007
Commodity price:		
Electricity contracts	**$ 102**	$ (137)

In assessing the fair value of EME s non-trading derivative financial instruments, EME uses quoted market prices and forward market prices adjusted for credit risk. 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 increase in fair value of electricity contracts at September 30, 2008 as compared to December 31, 2007 is attributable to a decline in the average market prices for power as compared to contracted prices at September 30, 2008, which is the valuation date. The following table summarizes the maturities and the related fair value, primarily based on actively traded prices, of EME s commodity derivative assets and liabilities as of September 30, 2008:

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 99	$ 21	$ 78	$	$
Price based on models and other valuation methods	3		3		
Total	**$ 102**	**$ 21**	**$ 81**	**$**	**$**

Prices actively quoted in the preceding table includes derivatives whose fair value is based on quoted market prices and forward market prices adjusted for credit risk.

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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, 2008 and December 31, 2007, are set forth below:

	September 30, 2008		December 31, 2007	
In millions	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Electricity contracts	**$ 263**	**$ 165**	$ 141	$ 9
Other	**3**	**2**		
	$ 266	**$ 167**	$ 141	$ 9

The change in the fair value of trading contracts for the nine months ended September 30, 2008, was as follows:

In millions	
Fair value of trading contracts at January 1, 2008	**$ 132**
Net gains from energy trading activities	**143**
Amount realized from energy trading activities	**(161)**
Other changes in fair value	**(15)**
Fair value of trading contracts at September 30, 2008	**$ 99**

EME adopted SFAS No. 157 effective January 1, 2008. The standard established a hierarchy for fair value measurements. See Edison International Notes to Consolidated Financial Statements Note 8. Fair Value Measurements, for further discussion of SFAS No. 157.

In the table below, prices actively quoted includes both exchange traded derivatives and non-exchange traded derivatives which are priced based on forward market prices adjusted for credit risk. Also in the table, fair value based on models and other valuation methods includes illiquid financial transmission rights and over-the-counter derivatives at illiquid locations and long-term power agreements which would be considered Level 3 derivative positions. For long-term power agreements, EME s subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit and liquidity

The following table summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities (as of September 30, 2008):

In millions	**Total Fair Value**	**Maturity <1 year**	**Maturity 1 to 3 years**	**Maturity 4 to 5 years**	**Maturity >5 years**
Prices actively quoted	$ (39)	$ (32)	$ (6)	$ (1)	$
Prices based on models and other valuation methods	138	58	26	26	28
Total	**$ 99**	**$ 26**	**$ 20**	**$ 25**	**$ 28**

Credit Risk

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

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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.

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The credit risk exposure from counterparties of merchant energy hedging and trading activities is measured as the sum of net receivables (accounts receivable less accounts payable) and the current fair value of net derivative assets. EME s subsidiaries enter into master agreements and other arrangements in conducting such activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. At September 30, 2008, the balance sheet exposure as described above, broken down by the credit ratings of EME s counterparties, was as follows:

In millions	September 30, 2008		
Credit Rating[(1)]	Exposure[(2)]	Collateral	Net Exposure
A or higher	$ 140	$	$ 140
A-	56		56
BBB+	56	(1)	55
BBB	87	(6)	81
BBB-	31		31
Below investment grade	21	(4)	17
Total	**$ 391**	**$ (11)**	**$ 380**

(1) EME assigns a credit rating based on the lower of a counterparty s S&P or Moody s rating. For ease of reference, the above table uses the S&P classifications to summarize risk, but reflects the lower of the two credit ratings.

(2) Exposure excludes amounts related to contracts classified as normal purchase and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheet, except for any related accounts receivable.

The credit risk exposure set forth in the above table is comprised of $197 million of net accounts receivable and payables and $194 million representing the fair value of derivative contracts. The exposure is based on master netting agreements with the related counterparties.

Included in the table above are exposures to financial institutions with credit ratings of A- or above. Due to recent developments in the financial markets, the credit ratings may not be reflective of the related credit risks. See Edison International: Current Developments Financial Markets and Economic Conditions for further discussion. The total net exposure to financial institutions at September 30, 2008 was $129 million. This total net exposure excludes positions with Lehman Brothers Holdings and its subsidiaries. Five financial institutions comprise 31% of the net exposure above with the largest single net exposure with a financial institution representing 18%. For further discussion, see Edison International: Current Developments Financial Markets and Economic Conditions Bankruptcy of Lehman Brothers Holdings and Subsidiaries. In addition to the amounts set forth in the above table, EME s subsidiaries have posted a $147 million cash margin in the aggregate with PJM, NYISO, MISO, clearing brokers and other counterparties to support hedging and trading activities. Margining posted to support these activities also exposes EME to credit risk of the related entities.

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 project.

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.

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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 50% of EME s consolidated operating revenues for the nine months ended September 30, 2008. Moody s rates PJM s debt Aa3. PJM, an ISO with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At September 30, 2008, EME s account receivable due from PJM was $57 million.

EME also derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Illinois plants to Commonwealth Edison under load requirements services contracts. Sales under these contracts accounted for 13% of EME s consolidated operating revenues during the nine months ended September 30, 2008. Commonwealth Edison s senior unsecured debt ratings are BBB- by S&P and Ba1 by Moody s. At September 30, 2008, EME s account receivable due from Commonwealth Edison was $17 million.

For the nine months ended September 30, 2008, a third customer, Constellation Energy Commodities Group, Inc., accounted for 13% of EME s consolidated operating revenues. Sales to Constellation are primarily generated from EME s merchant plants and largely consist of energy sales under forward contracts. The contract with Constellation is guaranteed by Constellation Energy Group, Inc., which has a senior unsecured debt rating of BBB by S&P and Baa2 by Moody s. At September 30, 2008, EME s account receivable due from Constellation was $26 million.

The terms of EME s wind turbine supply agreements contain significant obligations of the suppliers in the form of manufacturing and delivery of turbines and payments for delays in delivery and for failure to meet performance obligations and warranty indemnifications. EME reliance on these contractual provisions is subject to credit risks. Generally, these are unsecured obligations of the turbine manufacturer. A material adverse development with respect to a turbine supplier may have material impact on EME s wind projects.

Edison Capital s investments may be affected by the financial condition of other parties, the performance of the asset, economic conditions and other business and legal factors. Edison Capital generally does not control operations or management of the projects in which it invests and must rely on the skill, experience and performance of third party project operators or managers. These third parties may experience financial difficulties or otherwise become unable or unwilling to perform their obligations. Edison Capital s investments generally depend upon the operating results of a project with a single asset. These results may be affected by general market conditions, equipment or process failures, disruptions in important fuel supplies or prices, or another party s failure to perform material contract obligations, and regulatory actions affecting utilities purchasing power from the leased assets. Edison Capital has taken steps to mitigate these risks in the structure of each project through contract requirements, warranties, insurance, collateral rights and default remedies, but such measures may not be adequate to assure full performance. In the event of default, lenders with a security interest in the asset may exercise remedies that could lead to a loss of some or all of Edison Capital s investment in that asset.

At September 30, 2008, Edison Capital had a net leveraged lease investment, before deferred taxes, of $53 million in three aircraft leased to American Airlines. American Airlines reported net losses for its first, second and third quarters in 2008 and previously reported losses for a number of years prior to 2006. 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, 2008, American Airlines was current in its lease payments to Edison Capital.

Interest Rate Risk

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EMG 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 EMG s consolidated long-term obligations (including current portion) was $4.4 billion at September 30, 2008, compared to the carrying value of $4.83 billion.

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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. In light of current market conditions, Edison International borrowed against its credit facility. The proceeds were invested in U.S. treasury bills and U.S. treasury and government agency money market funds. At September 30, 2008, Edison International (parent) had approximately $316 million of cash and cash equivalents on hand.

On March 12, 2008, Edison International (parent) amended its existing $1.5 billion credit facility, extending the maturity to February 2013 while retaining existing borrowing costs as specified in the facility. The amendment also provides four extension options which, if all exercised, and agreed to by lenders, will result in a final termination of February 2017.

The following table summarizes the status of the Edison International (parent) credit facility at September 30, 2008:

In millions	Edison International (parent)
Commitment	$ 1,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(62)
	1,438
Outstanding borrowings	(250)
Outstanding letters of credit	
Amount available	$ 1,188

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB is one of the lenders in Edison International s (parent) credit agreement representing a total commitment of $74 million. This subsidiary fully funded $12 million of Edison International s (parent) borrowing request, which remains outstanding.

Edison International (parent) s cash requirements for the 12-month period following September 30, 2008 are expected to consist of:

- Dividends to common shareholders. The Board of Directors of Edison International declared a $0.305 per share quarterly dividend in December 2007, February 2008, April 2008, and September 2008. The dividends were paid in January 2008, April 2008, July 2008, and October 2008, respectively;
- Maturity and interest payments on debt outstanding under the credit facility;
- Intercompany related debt; and
- General and administrative expenses.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand, external borrowings and dividends and/or borrowings from its subsidiaries. The ability of subsidiaries to make dividend payments to Edison International is dependent on various factors as described below.

SCE may pay dividends to Edison International subject to CPUC restrictions. 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

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reduce the common equity component of SCE s capital structure below the authorized level on a 13-month weighted average basis (see SCE: Liquidity Dividend Restrictions and Debt Covenants for further discussion). The CPUC has also mandated that SCE s dividend policy shall continue to be established by SCE s Board of Directors as if SCE were a stand-alone utility and that the capital requirements of SCE be given first priority by the Boards of Directors of Edison International and SCE 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. The Board of Directors of SCE declared a $25 million dividend which was paid in January 2008 and three $100 million dividends which were paid in April 2008, July 2008, and October 2008, respectively.

EMG s ability to pay dividends to Edison International is dependent on its subsidiaries ability to pay dividends to EMG. EME s corporate credit facility contains covenants that restrict its ability, and the ability of several of its subsidiaries, to pay dividends in the case of any event of default under the facility. As of September 30, 2008, EME was not in default under its credit facility (see EMG: Liquidity Dividend Restrictions in Major Financings for further discussion). In addition, Edison Capital loaned $120 million to Edison International in January 2008 (total outstanding as of September 30, 2008 is $170 million).

EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

Federal and State Income Taxes

Edison International remains subject to examination and administrative appeals by the IRS for tax years 1994 and forward. Edison International is challenging certain IRS deficiency adjustments for tax years 1994 1999 with the Administrative Appeals branch of the IRS and Edison International is currently under active IRS examination for tax years 2000 2006. During the third quarter of 2008, the IRS commenced an examination of tax years 2003 2006. In addition, the statute of limitations remains open for tax years 1986 1993, which has allowed Edison International to file certain affirmative claims related to these years. 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 the 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

The table below presents Edison International s earnings for the three- and nine-month periods ended September 30, 2008 and 2007, and the relative contributions by its subsidiaries.

In millions	Earnings (Loss)	
Three-Month Period Ended September 30,	**2008**	**2007**
Earnings (Loss) from Continuing Operations:		
SCE	**$ 235**	$ 262
EMG	**208**	207
Edison International (parent) and other	**(10)**	(4)
Edison International Consolidated Earnings from Continuing Operations	**433**	465
Earnings (Loss) from Discontinued Operations	**6**	(4)
Edison International Consolidated	**$ 439**	$ 461

In millions	Earnings (Loss)	
Nine-Month Period Ended September 30,	**2008**	**2007**
Earnings (Loss) from Continuing Operations:		
SCE	**$ 542**	$ 587
EMG	**479**	313
Edison International (parent) and other	**(22)**	(14)
Edison International Consolidated Earnings from Continuing Operations	**999**	886
Earnings from Discontinued Operations		1
Edison International Consolidated	**$ 999**	$ 887

Earnings (Loss) from Continuing Operations

Edison International s earnings from continuing operations were $433 million and $999 million for the three- and nine-month periods ended September 30, 2008, respectively, compared with earnings from continuing operations of $465 million and $886 million for the comparable periods in 2007.

SCE s earnings from continuing operations were $235 million and $542 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to $262 million and $587 million for the respective periods in 2007. SCE s quarter and year-to-date earnings reflect a charge of $49 million associated with a decision adopted by the CPUC which required SCE to refund or forego incentives and imposed a penalty related to previously earned customer satisfaction and employee safety incentives. Earnings also reflect higher operating income and lower financing costs. The year-to-date earnings also reflect a $31 million tax benefit recognized in 2007 related to the income tax treatment of certain costs including those associated with environmental remediation and lower income taxes.

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EMG s earnings from continuing operations were $208 million and $479 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to $207 million and $313 million for the respective periods in 2007. EMG s quarter earnings reflect higher gross margin at EMG s Homer City facilities and EMG s Illinois plants offset by a charge related to hedge contracts with Lehman Brothers Commodity Services, Inc., lower income from the Big 4 projects and Edison Capital, lower interest income and other. EMG s year-to-date increase was mainly due to a $148 million, after tax, loss on early extinguishment of debt recorded in 2007, higher gross margin at EMG s Illinois plants and higher generation and average realized prices, and higher energy trading income at EMMT. These year-to-date increases were partially offset by lower income from the Big 4 projects and Homer City, lower interest income and higher project development costs associated with EME s growth activities.

Operating Revenue

Electric Utility Revenue

The following table sets forth the major components of electric utility revenue:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2008**	2007	**2008**	2007
Electric utility revenue				
Retail billed and unbilled revenue	**$ 3,192**	$ 3,125	**$ 7,334**	$ 7,312
Balancing account (over)/under collections	**(222)**	(300)	**35**	(409)
Sales for resale	**141**	168	**466**	333
SCE s VIEs	**129**	81	**343**	286
Other (including intercompany transactions)	**44**	139	**210**	373
Total	**$ 3,284**	$ 3,213	**$ 8,388**	$ 7,895

SCE s retail sales represented approximately 90% and 88% of electric utility revenue for the three- and nine-month periods ended September 30, 2008, respectively, compared to approximately 88% and 87% for both of the comparable periods in 2007. Due to warmer weather during the summer months and SCE s rate design, electric utility revenue during the third quarter of each year is generally higher than other quarters.

Total electric utility revenue increased by $71 million and $493 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007 (as shown in the table above). The variances for the revenue components are as follows:

Retail billed and unbilled revenue increased $67 million and $22 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The quarter and year-to-date increases reflect a rate increase (including impact of tiered rate structure) of $70 million and $29 million, respectively, and a sales volume decrease of $3 million and $7 million, respectively. The increase for the quarter and year-to-date was due to minor variations of usage by rate class.

SCE recognizes revenue, subject to balancing account treatment, equal to the amount of the actual costs incurred and up to its authorized revenue requirement. Any revenue collected in excess of actual costs incurred or above the authorized revenue requirement is not recognized as revenue and is deferred and recorded as regulatory liabilities. Costs incurred in excess of revenue billed are deferred in a balancing account and recorded as regulatory assets for recovery in future rates. If amounts collected are below the authorized revenue requirement the difference is recognized as revenue and recorded as regulatory assets for recovery in future rates (see Provision for Regulatory Adjustment Clauses Net discussed below). For the three months ended September 30, 2008 and 2007, SCE deferred approximately $222 million and $300 million, respectively and for the nine months ended September 30, 2008 and 2007, SCE recognized approximately $35 million and deferred approximately $409 million, respectively. The quarter change in balancing account revenue is primarily due to SCE deferring less revenue in 2008. The year-to-date change in balancing account revenue is primarily due to SCE recognizing deferred revenue resulting from prior year over-collections.

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Sales for resale represent 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 for the three months ended September 30, 2008 due to a lesser amount of excess energy available for resale during the quarter. Sales for resale revenue increased for the nine months ended September 30, 2008 due to higher excess energy in 2008, compared to the same periods in 2007, resulting from increased kWh purchases from new contracts, as well as increased sales from least cost dispatch energy. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.

The decrease in other revenue for the three- and nine-month periods ended September 30, 2008 was primarily related to lower net investment earnings and higher other-than-temporary impairment losses from SCE s nuclear decommissioning trust due to a volatile stock market environment. Due to regulatory treatment, investment impairment losses and trust earnings and losses 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 $583 million and $1.68 billion for the three- and nine-month periods ended September 30, 2008, respectively, compared to $671 million and $1.8 billion for the same respective periods in 2007.

Nonutility Power Generation Revenue

The following table sets forth the major components of nonutility power generation revenue:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2008**	**2007**	**2008**	**2007**
EMG s Illinois plants	**$ 501**	$ 449	**$ 1,360**	$ 1,214
EMG s Homer City facilities	**236**	199	**548**	573
EMMT	**46**	41	**138**	103
Other	**30**	22	**97**	62
Nonutility power generation	**$ 813**	$ 711	**$ 2,143**	$ 1,952

Nonutility power generation revenue increased $102 million and $191 million for the three- and nine-month periods ended September 30, 2008, respectively, as compared to the same periods in 2007.

Nonutility power generation revenue from EMG s Illinois plants increased $52 million and $146 million for the three- and nine-month periods ended September 30, 2008, respectively. The third quarter and year-to-date increases are due to higher average realized energy and capacity prices and unrealized gains discussed below, partially offset by a $24 million unrealized loss related to power contracts due to the bankruptcy of Lehman Brothers Holdings.

Nonutility power generation revenue from EMG s Homer City facilities increased $37 million for the three months ended September 30, 2008 and decreased $25 million nine months ended September 30, 2008. The third quarter increase was primarily attributable to higher average realized energy and capacity prices and an increase in unrealized gains related to hedge contracts discussed below. The year-to-date decrease was primarily attributable to lower generation. Higher forced outages, lower off-peak dispatch and extended planned overhauls in 2008 contributed to lower generation. The average realized energy price for the nine months ended September 30, 2008 was below the 24-hour PJM average market price at the Homer City busbar primarily due to

effective hedge prices being below market prices for the same period. For further discussion, see EMG: Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Homer City Facilities.

Included in operating revenue for EMG s Illinois plants were unrealized losses of $7 million and $8 million for the third quarters of 2008 and 2007, respectively, and $15 million and $26 million for the nine months ended September 30, 2008 and 2007, respectively. In 2008, unrealized losses included $24 million from power contracts for 2009 and 2010 with Lehman Brothers Commodity Services, Inc. These contracts qualified as cash flow hedges under SFAS No. 133 until EME dedesignated the contracts as such, effective September 12, 2008. Since the power contracts no longer qualify as cash flow hedges under SFAS No. 133 due to non-performance risk, the subsequent change in fair value was recorded as an unrealized loss during the third quarter of 2008. Unrealized gains (losses) were also attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges under SFAS No. 133 and power contracts that did not qualify for hedge accounting under SFAS No. 133 (sometimes referred to as economic hedges). These energy contracts were entered into to hedge the price risk related to projected sales of power. See EMG: Market Risk Exposures Commodity Price Risk and EMG: Market Risk Exposures Accounting for Energy Contracts for more information regarding forward market prices and the write-off of the power contracts, respectively.

EME seeks to generate profit by utilizing its subsidiary, EMMT, to engage in trading activities in those markets in which it is active as a result of its management of the merchant power plants of Midwest Generation and Homer City. EMMT trades power, fuel and transmission congestion primarily in the eastern power grid using products available over the counter, through exchanges and from ISOs. The majority of EMMT s trading activities are related to congestion contracts and short-term power arbitrage positions between locations. Nonutility power generation revenue from energy trading activities at EMMT increased $5 million and $35 million for the three- and nine-month periods ended 2008, respectively, compared to the corresponding periods in 2007. The 2008 increase in nonutility power generation revenue from energy trading activities resulted from increased congestion and market volatility in key markets.

In April 2008, EMMT entered into three load services requirements contracts in Maryland with local utilities. Under the terms of the load services requirements contracts, EMMT is obligated to supply a portion of each utility s load at fixed prices that vary based on periods specified in the contracts. EMMT is obligated to pay for the cost of supply at each utility s load zones including, energy, capacity, ancillary services and renewable energy credits. The estimated load for the period October 1, 2008 through September 30, 2010 is approximately 4 million megawatt-hours. EMMT has entered into futures contracts to substantially hedge the energy price risk related to these contracts. The above contracts are recorded as derivatives with the change in fair value reflected in trading income above.

EMG s other project revenue increased by $8 million and $35 million for the three- and nine-month periods ended September 30, 2008, respectively. The quarter and year-to-date increases were primarily due to the commencement of commercial operation of wind projects that did not have comparable results in 2007.

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

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Operating Expenses

Fuel Expense

In millions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
SCE	**$ 415**	$ 310	**$ 1,161**	$ 904
EMG	**220**	192	**564**	521
Edison International Consolidated	**$ 635**	$ 502	**$ 1,725**	$ 1,425

SCE s fuel expense increased $105 million and $257 million for the three- and nine-month periods ended September 30, 2008, as compared to the same periods in 2007. The quarter and year-to-date increases were mainly due to an increase at SCE s Mountainview plant of $15 million and $100 million resulting from higher gas costs in 2008; higher gas costs at SCE s VIEs which resulted in increases of $80 million and $145 million; an increase of $5 million at SCE s Mohave plant representing use tax due on coal consumed during the March 2005 through December 2005 period; and a $5 million increase at SCE s Four Corners coal facility resulting from higher coal costs in 2008. The year-to date variance was also due to a decrease of $5 million mainly due to refueling and maintenance outages at SCE s San Onofre Unit 3 and SCE s Palo Verde Unit 3 during the third quarter of 2008.

EMG s fuel expense increased $28 million and $43 million for the three- and nine-month periods ended September 30, 2008, as compared to the same period in 2007. The year-to-date increase was mainly due to higher coal and transportation costs per megawatt hour at EMG s Illinois plants in 2008.

Purchased-Power Expense

The following is a summary of SCE purchased-power expense:

In millions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Purchased-power	**$ 1,360**	$ 1,146	**$ 3,045**	$ 2,389
Unrealized (gains) losses on economic hedging activities net	**617**	80	**131**	(14)
Realized (gains) losses on economic hedging activities net	**(14)**	58	**(39)**	111
Energy settlements and refunds	**(1)**		**(26)**	(55)
Total purchased-power expense	**$ 1,962**	$ 1,284	**$ 3,111**	$ 2,431

Total purchased-power expense increased $678 million and $680 million for the three- and nine-month periods ended September 30, 2008, respectively, as compared to the same periods in 2007.

Purchased power, in the table above, increased $214 million and $656 million for the three- and nine-month periods ended September 30, 2008, respectively, as compared to the same periods in 2007. The quarter and year-to-date increases were due to: higher bilateral energy purchases of $160 million and $410 million, respectively, resulting from higher costs per kWh due to higher gas prices and increased kWh purchases; higher QF purchased-power expense of $55 million and $120 million, respectively, resulting from increased kWh purchases and an increase in the average spot natural gas prices for certain contracts (as discussed further below). The quarter increase also reflects higher exchange energy purchases of $10 million. The year-to-date increase also reflects higher ISO-related energy costs of $115 million.

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Net realized and unrealized losses on economic hedging activities, in the table above, was $603 million and $138 million for the three months ended September 30, 2008 and 2007, respectively. Net realized and unrealized losses on economic hedging activities, in the table above, was $92 million and $97 million for the nine months ended September 30, 2008 and 2007, respectively (see SCE: Market Risk Exposures Commodity Price Risk for further discussion). The changes in net realized and unrealized losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008, compared to the same periods in 2007. Due to expected recovery through regulatory mechanisms realized and unrealized gains and losses may temporarily affect cash flows, but are not expected to affect earnings (see SCE: Market Risk Exposures Commodity Price Risk for further discussion).

SCE energy settlement refunds and generator settlements decreased $29 million for the nine months ended September 30, 2008 as compared to the same period in 2007 (see SCE: Regulatory Matters Current Regulatory Developments FERC Refund Proceedings for further discussion).

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. Energy payments for most renewable QFs are at a fixed price of 5.37¢ per-kWh. In late 2006, certain renewable QF contracts were amended and energy payments for these contracts are at a fixed price of 6.15¢ per-kWh, effective May 2007.

Provisions for Regulatory Adjustment Clauses Net

Provisions for regulatory adjustment clauses net decreased $671 million and $475 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The quarter and year-to date variances reflect a decrease of $75 million and $190 million, respectively, as a result of the rate reduction notes being fully repaid as of December 31, 2007 (see SCE: Liquidity Rate Reduction Notes in the year-ended 2007 MD&A). The quarter variance also reflects net unrealized losses on economic hedging activities of approximately $617 million and $80 million for the three months ended September 30, 2008 and 2007, respectively (discussed above in Purchased-Power Expense); lower exchange energy of $10 million; and approximately $50 million resulting from higher net under-collections of purchased-power and fuel expenses resulting from higher procurement costs which are being recovered through regulatory mechanisms. The year-to-date variance also reflects net unrealized losses on economic hedging activities of approximately $131 million in 2008, compared to gains of $14 million for the same period in 2007, respectively (discussed above in Purchased-Power Expense); approximately $29 million related to a generator settlement recorded in 2007; higher firm transmission rights costs of $45 million; and $70 million of higher net under-collections of purchased-power, fuel, and operation and maintenance expenses resulting from higher procurement costs which are being recovered through regulatory mechanisms, partially offset by the Midway-Sunset settlement which was charged/refunded to ratepayers through regulatory mechanisms (see Other Developments Midway-Sunset Cogeneration Company for further information).

Other Operation and Maintenance Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2008**	2007	**2008**	2007
SCE	**$ 771**	$ 780	**$ 2,324**	$ 2,152
EMG	**242**	226	**758**	716
Edison International (parent) and other	**12**	7	**27**	25
Edison International Consolidated	**$ 1,025**	$ 1,013	**$ 3,109**	$ 2,893

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SCE s other operation and maintenance expense decreased $9 million for the three months ended September 30, 2008 and increased $172 million for the nine months ended September 30, 2008, compared to the same periods in 2007. The quarter decrease was primarily due to a decrease of approximately $25 million related to lower transmission and distribution maintenance costs partially offset by an increase of $20 million related to higher administrative and general costs. Certain of SCE s operation and maintenance expense accounts are recovered through regulatory mechanisms approved by the CPUC and do not impact earnings. The costs associated with these regulatory balancing accounts increased $65 million for the nine months ended September 30, 2008 mainly related to higher demand-side management costs and energy efficiency costs. The increases in operation and maintenance expense for the year-to-date period also reflect: higher administrative and general costs of $60 million; higher generation expenses of $30 million related to maintenance and refueling outage expenses at San Onofre and higher overhaul and outage costs at Four Corners and Palo Verde; higher customer service costs (including labor) of $10 million; and higher employer payroll taxes of $15 million. The year-to-date variance also reflects a decrease of approximately $10 million related to lower transmission and distribution maintenance costs.

EMG s other operation and maintenance expense increased $16 million and $42 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The 2008 increases were mainly due to higher plant maintenance expenses at EME s Homer City facilities resulting from higher forced outages and extended planned overhauls in 2008. The increases also reflect higher labor costs and consulting expense resulting from EME s growth activities.

Depreciation, Decommissioning and Amortization Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2008**	**2007**	**2008**	**2007**
SCE	**$ 211**	$ 267	**$ 750**	$ 813
EMG	**51**	43	**143**	124
Edison International Consolidated	**$ 262**	$ 310	**$ 893**	$ 937

SCE s depreciation, decommissioning and amortization expense decreased $56 million and $63 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The quarter and year-to-date variances were due to a decrease of $80 million and $140 million, respectively, in nuclear decommissioning trust earnings and higher other-than-temporary impairment losses associated with the nuclear decommissioning trust funds primarily related to a volatile stock market environment. Due to its regulatory treatment, investment impairment losses and trust earnings and losses are recorded in electric utility revenue and are offset in decommissioning expense and have no impact on net income. The quarter and year-to-date decreases were partially offset by an increase in depreciation expense of $20 million and $60 million, respectively, resulting from additions to transmission and distribution assets (see SCE: Liquidity Capital Expenditures for a further discussion); and a $17 million cumulative depreciation rate adjustment recorded in the second quarter of 2008.

EMG s depreciation and amortization expense increased $8 million and $19 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007, primarily attributable to higher depreciation expense for wind projects.

(Gain) on Buyout of Contract and (Gain)/Loss on Sale of Assets

(Gain) on buyout of contract and (gain)/loss on sale of assets increased $75 million for the nine months ended September 30, 2008. The 2008 quarter and year-to-date increases were primarily due to a $41 million gain on a termination of a lease. In March 2008, First Energy exercised an early buyout right under the terms of an existing

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lease agreement with Edison Capital related to Unit No. 2 of the Beaver Valley Nuclear Power Plant. The termination date of the lease under the early buyout option was June 1, 2008. Proceeds from the sale were $72 million. Edison Capital recorded a pre-tax gain of $41 million ($23 million after tax) during the second quarter of 2008. The year-to-date increase also reflects approximately $7 million in gains on the sale of investments at Edison Capital and gains of $8 million from the sale of SO_2 emission allowances at SCE. Due to regulatory treatment, gains from the sale of emission allowances are offset in provision for regulatory adjustment clauses net and, as a result, have no impact on net income. The increase also reflects a gain of $15 million recorded during the first quarter of 2008 related to a buyout of a fuel contract (see Commitments, Guarantees and Indemnities Fuel Supply Contracts for further discussion).

Other Income and Deductions

Interest and Dividend income

In millions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
SCE	**$ 2**	$ 13	**$ 12**	$ 34
EMG	**7**	25	**31**	87
Edison International (parent) and other		2	**1**	4
Edison International Consolidated	**$ 9**	$ 40	**$ 44**	$ 125

SCE s interest income decreased $11 million and $22 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The 2008 decreases were mainly due to lower under-collection balances in certain balancing accounts and lower interest rates applied to those under-collections.

EMG s interest and dividend income decreased $18 million and $56 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The 2008 decreases were primarily attributable to lower average cash equivalents and short-term investment balances and lower interest rates in 2008 compared to 2007.

Equity in Income from Partnerships and Unconsolidated Subsidiaries Net

Equity in income from partnerships and unconsolidated subsidiaries net decreased $4 million and $32 million for the three- and nine-month periods ended September 30, 2008, respectively, compared to the same periods in 2007. The decrease in 2008 was mainly due to gains from Edison Capital s global infrastructure funds recorded in 2007.

Other Nonoperating Income

In millions	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
SCE	**$ 20**	$ 29	**$ 69**	$ 68
EMG	**3**	6	**9**	7
Edison International Consolidated	**$ 23**	$ 35	**$ 78**	$ 75

SCE s other nonoperating income decreased $9 million for the three months ended September 30, 2008, compared to the same period in 2007. The decrease for the quarter was due to payments received for settlement of claims related to the natural gas purchased contracts for one of SCE s VIE projects recorded in the third quarter of 2007.

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Interest Expense Net of Amounts Capitalized

	Three Months Ended September 30,		Nine Months Ended September 30,	
In millions	**2008**	**2007**	**2008**	**2007**
SCE	**$ 104**	$ 117	**$ 297**	