EDISON INTERNATIONAL
Form 10-K
March 01, 2010

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Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

o **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 **(State or other jurisdiction of incorporation or organization)**	**95-4137452** **(I.R.S. Employer Identification No.)**
2244 Walnut Grove Avenue **(P.O. Box 976)** **Rosemead, California** **(Address of principal executive offices)**	**91770** **(Zip Code)**

(626) 302-2222
(Registrant's telephone number, including area code)

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

Title of each class

	Name of each exchange on which registered
Common Stock, no par value	**New York**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No þ

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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

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

Large Accelerated Filer þ Accelerated Filer o Non-accelerated Filer o Smaller Reporting Company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of registrant's voting stock held by non-affiliates was approximately $10.25 billion on or about June 30, 2009, based upon prices reported on the New York Stock Exchange. As of February 25, 2010, there were 325,811,206 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents listed below have been incorporated by reference into the parts of this report so indicated.

(1) Designated portions of the Proxy Statement relating to registrant's 2010 Annual Meeting of Shareholders	Part III

TABLE OF CONTENTS

Table of Contents

Table of Contents

Table of Contents

Table of Contents

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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," "intends," "plans," "probable," "may," "will," "could," "would," "should," and variations of such words and similar expressions, or discussions of strategy or of plans, are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ from those currently expected, or that otherwise could impact Edison International, include, but are not limited to:

- environmental laws and regulations, at both state and federal levels, or changes in the application of those laws, that could require additional expenditures or otherwise affect the cost and manner of doing business;

- cost of capital and the ability to borrow funds and access the capital markets on reasonable terms;

- cost and availability of electricity, including 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;

- 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;

- changes in interest rates, rates of inflation, including those rates which may be adjusted by public utility regulators;

- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and price mitigation strategies adopted by Independent System Operators and Regional Transmission Organizations;

- risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage issues, failure, availability, efficiency, output, cost of repairs and retrofits, in each case, of equipment, and availability and cost of spare parts;

- availability and creditworthiness of counterparties and the resulting effects on liquidity in the power and fuel markets and/or the ability of counterparties to pay amounts owed in excess of collateral provided in support of their obligations;

Table of Contents

- cost and availability of labor, equipment and materials;
- ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities and wildfire-related liability, and to recover the costs of such insurance;
- ability to recover uninsured losses in connection with wildfire-related liability;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- potential for penalties or disallowances caused by non-compliance with applicable laws and regulations;
- outcome of disputes with state tax authorities regarding tax positions taken by Edison International;
- cost and availability of coal, natural gas, fuel oil, and nuclear fuel, and related transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;
- 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;
- ability to provide sufficient collateral in support of hedging activities and power and fuel purchased;
- risk of counterparty default in hedging transactions or power-purchase and fuel contracts;
- weather conditions, natural disasters and other unforeseen events;
- risks inherent in the development of generation projects and transmission and distribution infrastructure replacement and expansion projects, including those related to project site identification, construction, permitting, and governmental approvals; and
- risks that competing transmission systems will be built by merchant transmission providers in SCE's territory.

See "Risk Factors" in Part I, Item 1A of this report for additional information on risks and uncertainties that could cause results to differ from those currently expected or that otherwise could impact Edison International or its subsidiaries.

Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this report. 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 U.S. Securities and Exchange Commission.

Except when otherwise stated, 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.

Table of Contents

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
AOI	Adjusted Operating Income
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
BACT	best available control technology
BART	best available retrofit technology
Bcf	billion cubic feet
Big 4	Kern River, Midway-Sunset, Sycamore and Watson natural gas power projects
Btu	British thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury 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
CPS	Combined Pollutant Standard
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DCR	Devers-Colorado River
DOE	U.S. Department of Energy
DOJ	U.S. Department of Justice
DRA	Division of Ratepayer Advocates
DWP	Los Angeles Department of Water & Power
EME	Edison Mission Energy
EMG	Edison Mission Group Inc.
EMMT	Edison Mission Marketing & Trading, Inc.
EPS	earnings per share
ERRA	energy resource recovery account
EWG	Exempt Wholesale Generator
Exelon Generation	Exelon Generation Company LLC
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGIC	Financial Guarantee Insurance Company
Fitch	Fitch Ratings
FTRs	firm transmission rights
Four Corners	coal-fired electric generating facility located in Farmington, New Mexico
GAAP	generally accepted accounting principles
Global Settlement	A settlement between Edison International and the IRS that resolved alleged deficiencies in 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.

Table of Contents

GRC	General Rate Case
GWh	Gigawatt-hours
Homer City	EME Homer City Generation L.P.
Illinois EPA	Illinois Environmental Protection Agency
Illinois PCB	Illinois Pollution Control Board
Investor-Owned Utilities	SCE, SDG&E and PG&E
IRS	Internal Revenue Service
ISO	Independent System Operator
kWh(s)	kilowatt-hour(s)
LIBOR	London Interbank Offered Rate
MD&A	Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in this report
MEHC	Mission Energy Holding Company
Midwest Generation	Midwest Generation, LLC
Midwest Generation Plants	EME's largest power plants (fossil fuel) located in Illinois
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
NAAQS	national ambient air quality standards
NAPP	Northern Appalachian
NERC	North American Electric Reliability Corporation
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NOV	notice of violation
NO_x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
PADEP	Pennsylvania Department of Environmental Protection
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
PSD	Prevention of Significant Deterioration
PUHCA 2005	Public Utility Holding Company Act of 2005
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RGGI	Regional Greenhouse Gas Initiative
RICO	Racketeer Influenced and Corrupt Organization
ROE	return on equity
RPM	reliability pricing model
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
San Onofre	San Onofre Nuclear Generating Station
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company

Table of Contents

SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
SIP(s)	State Implementation Plan(s)
SO_2	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
TURN	The Utility Reform Network
US EPA	U.S. Environmental Protection Agency
VIE(s)	variable interest entity(ies)

Table of Contents

PART I

ITEM 1. BUSINESS

INTRODUCTION

Edison International was incorporated on April 20, 1987, under the laws of the State of California for the purpose of becoming the parent holding company of Southern California Edison Company ("SCE"), a California public utility corporation, Edison Mission Energy ("EME"), an independent power producer, and Edison Capital, an infrastructure finance company. Beginning in 2006, EME and Edison Capital have been presented on a consolidated basis as Edison Mission Group Inc. ("EMG"), reflecting the integration of management and personnel at EME and Edison Capital. As a holding company, Edison International's progress and outlook are dependent on developments at its operating subsidiaries.

At December 31, 2009, Edison International and its subsidiaries had an aggregate of 19,244 full-time employees, of which 53 were employed directly by Edison International. The principal executive offices of Edison International are located at 2244 Walnut Grove Avenue, P.O. Box 976, Rosemead, California 91770, and the telephone number is (626) 302-2222.

Edison International makes available on its investor website, www.edisoninvestor.com, its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Proxy Statement and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act, as soon as reasonably practicable after Edison International electronically files such material with, or furnishes it to, the SEC. Such reports are also available on the SEC's internet website at www.sec.gov. The information contained on, or connected to, the Edison investor website is not incorporated by reference into this report.

Subsidiaries of Edison International

Edison International has three business segments for financial reporting purposes: an electric utility operation segment (SCE), a competitive power generation segment (EME), and a financial services provider segment (Edison Capital). Financial information about these segments and about geographic areas, for fiscal years 2009, 2008, and 2007, is contained in "Item 8. Edison International Notes to Consolidated Financial Statements Note 16. Business Segments" and incorporated herein by this reference. Additional information about each of these business segments appears below under the headings " Southern California Edison Company" and " Edison Mission Group Inc."

SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to a 50,000-square-mile area of central, coastal and southern California, excluding the City of Los Angeles and certain other cities. The SCE service territory includes over 400 cities and communities and a population of more than 13 million people. In 2009, SCE's total operating revenue was derived as follows: 42% commercial customers, 39% residential customers, 6% industrial customers, 2% resale sales, 6% public authorities, and 5% agricultural and other customers. SCE had 17,348 full-time employees at December 31, 2009. SCE's operating revenue was approximately $10 billion in 2009.

Table of Contents

SCE files separately an Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Proxy Statement and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act, as soon as reasonably practicable after SCE electronically files such material with, or furnishes it to, the SEC. Such reports are also available at www.edisoninvestor.com or on the SEC's internet website at www.sec.gov. The information contained on, or connected to, the Edison investor website is not incorporated by reference into this report.

EMG is the holding company for its principal wholly owned subsidiaries, EME and Edison Capital. EME is a holding company with subsidiaries and affiliates engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EME also conducts hedging and energy trading activities in competitive power markets through its Edison Mission Marketing & Trading, Inc. ("EMMT") subsidiary. At December 31, 2009, EME and its subsidiaries employed 1,843 people.

EME's subsidiaries or affiliates have typically been formed to own full or partial interests in one or more power plants and ancillary facilities, with each plant or group of related plants being individually referred to by EME as a project. EME's operating projects primarily consist of coal-fired generating facilities, natural gas-fired generating facilities and renewable energy facilities (primarily wind projects and one biomass project). As of December 31, 2009, EME's subsidiaries and affiliates owned or leased interests in 39 operating projects with an aggregate net physical capacity of 11,269 MW of which EME's *pro rata* share was 10,072 MW. At December 31, 2009, EME's subsidiaries and affiliates also owned two wind projects under construction totaling 390 MW of net generating capacity. EME's consolidated operating revenue in 2009 was approximately $2.4 billion.

EME files separately an Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act, as soon as reasonably practicable after EME electronically files such material with, or furnishes it to, the SEC. Such reports are also available www.edisoninvestor.com or on the SEC's internet website at www.sec.gov. The information contained on, or connected to, the Edison investor website is not incorporated by reference into this report.

Edison Capital has investments worldwide in energy and infrastructure projects, including power generation, electric transmission and distribution, transportation, and telecommunications. Edison Capital also has investments in affordable housing projects located throughout the United States. At the present time, no new investments are expected to be made by Edison Capital and the focus will be on managing the existing investment portfolio.

Regulation of Edison International and Subsidiaries

Edison International and its subsidiaries are subject to extensive regulation. As a public utility holding company, Edison International is subject to the Public Utility Holding Company Act. The PUHCA primarily obligates Edison International and its utility subsidiaries to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

Table of Contents

SCE's rates and operations are subject to extensive regulation by the CPUC, FERC, NRC, CEC, and CAISO. See "Southern California Edison Company Regulation of SCE." EME's operating projects are also subject to energy, environmental and other governmental laws and regulations at the federal, state and local levels, and EME is additionally subject to the market rules, procedures, and protocols of the markets in which it participates. See "Edison Mission Group Inc. Regulation." Both SCE and EME are also subject to the reliability standards for the bulk power system required by the North American Electric Reliability Corporation ("NERC").

Edison International is not a public utility under the laws of the State of California or any other state and is not subject to regulation as such by the CPUC or any similar agency. See "Southern California Edison Company Regulation of SCE" below for a description of the regulation of SCE by the CPUC. The 1988 CPUC decision authorizing SCE to reorganize into a holding company structure, however, contains certain conditions, which, among other things: (1) ensure CPUC access to books and records of Edison International and its affiliates which relate to transactions with SCE; (2) require Edison International and its subsidiaries to employ accounting and other procedures and controls to ensure full review by the CPUC and to protect against subsidization of nonutility activities by SCE's customers; (3) require that all transfers of market, technological, or similar data from SCE to Edison International or its affiliates be made at market value; (4) preclude SCE from guaranteeing any obligations of Edison International without prior written consent from the CPUC; (5) provide for royalty payments to be paid by Edison International or its subsidiaries in connection with the transfer of product rights, patents, copyrights, or similar legal rights from SCE; and (6) prevent Edison International and its subsidiaries from providing certain facilities and equipment to SCE except through competitive bidding. In addition, the decision provides that SCE shall maintain a balanced capital structure in accordance with CPUC decisions, that SCE's dividend policy shall continue to be established by SCE's Board of Directors as though SCE were a stand-alone utility company, and that the capital requirements of SCE, as deemed to be necessary to meet SCE's service obligations, shall receive first priority from the Boards of Directors of Edison International and SCE. The CPUC has also promulgated Affiliate Transaction Rules, which contain similar restrictions that apply to Edison International, as a holding company.

Financial Information About Geographic Areas

Financial information for geographic areas for Edison International can be found in "Item 8. Edison International Notes to Consolidated Financial Statements Note 16. Business Segments and Note 17. Acquisitions."

Table of Contents

SOUTHERN CALIFORNIA EDISON COMPANY

Regulation

CPUC

SCE's retail operations are subject to regulation by the CPUC. The CPUC has the authority to regulate, among other things, retail rates, energy purchases on behalf of retail customers, rate of return, rates of depreciation, issuance of securities, disposition of utility assets and facilities, oversight of nuclear decommissioning, and aspects of the construction, planning and project site identification of the electricity transmission system.

Resource Adequacy Requirements

The CPUC has established resource adequacy requirements, which require SCE to procure adequate electricity to meet its expected customer needs on both a system-wide and a local basis. SCE would be subject to penalties if it failed to meet the requirements. SCE complied with the resource adequacy requirements in 2009 and expects to comply in 2010.

Procurement of Renewable Resources

California law requires SCE to increase its procurement of energy from 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 or such later date as flexible compliance requirements may permit. Under the CPUC's current rules, the maximum penalty for inability to achieve renewable procurement targets is $25 million per year. SCE's ability to meet the RPS target depends largely on the ability of third parties to meet contractual obligations to deliver power to SCE. Flexible compliance rules, such as banking of past surplus and earmarking of future deliveries from executed contracts, are also available. SCE does not believe it will be assessed penalties for 2009 or prior years and cannot predict whether it will be assessed penalties for future years.

FERC

SCE's wholesale operations (including sales of electricity into the wholesale markets) are subject to regulation by the FERC. The FERC has the authority to regulate wholesale rates as well as other matters, including unbundled transmission service pricing, accounting practices, and licensing of hydroelectric projects.

CEC

The construction, planning, and project site identification of SCE's power plants within California are subject to the jurisdiction of the California Energy Commission ("CEC") (for plants 50 MW or greater). The CEC is responsible for forecasting future energy needs. These forecasts are used by the CPUC in determining the adequacy of SCE's electricity procurement plans. California law prohibits the CEC from siting or permitting a new nuclear power plant in California until it finds a federally approved and demonstrated method for the disposal of nuclear waste.

Table of Contents

Nuclear Power Plant Regulation

SCE is subject to the jurisdiction of the U.S. Nuclear Regulatory Commission ("NRC") with respect to its San Onofre and Palo Verde Nuclear Generating Stations. NRC requirements govern the granting, amendment, and extension of licenses for the construction and operation of nuclear power plants and subject those power plants to continuing oversight, inspection, and performance assessment with respect to plant operation and related activities.

San Onofre is currently addressing a number of regulatory and performance issues. The NRC is requiring SCE to take actions to provide greater assurance of compliance by San Onofre personnel with applicable NRC requirements and procedures. SCE is currently implementing plans to address the identified issues. The NRC has continued to affirm that San Onofre has been operated and is being operated safely; however, the cumulative impact of these regulatory and performance issues is an increase in management focus and other resources applied at San Onofre.

Information about nuclear decommissioning can be found in "Item 8. Edison International Notes to Consolidated Financial Statements Note 1. Summary of Significant Accounting Policies and Note 6. Commitments and Contingencies." Information about nuclear insurance can be found in "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

Transmission and Substation Facilities Regulation

The construction, planning and project site identification of SCE's transmission lines and substation facilities require the approval of many governmental agencies and compliance with various laws. These agencies include utility regulatory commissions such as the CPUC and other state regulatory agencies depending on the project location; the Independent System Operator ("ISO"), and other environmental, land management and resource agencies such as the Bureau of Land Management, the U.S. Forest Service, and the California Department of Fish and Game; and Regional Water Quality Control Boards. In addition, to the extent that SCE transmission line projects pass through lands owned or controlled by Native American tribes, consent and approval from the affected tribes and the Bureau of Indian Affairs will also be necessary for the project to proceed.

Relationship with Certain Affiliated Companies

SCE is subject to CPUC and FERC affiliate transaction rules and compliance plans governing the relationship between SCE and its affiliates.

Overview of Ratemaking Mechanisms

SCE sells electricity to retail customers at rates authorized by the CPUC. SCE sells transmission service and wholesale power at rates authorized by the FERC.

Base Rates

Base rates authorized by the CPUC and the FERC are intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its net investment in generation,

Table of Contents

transmission and distribution facilities (or "rate base"). These base rates provide for recovery of operations and maintenance costs, capital-related carrying costs (depreciation, taxes and interest) and a return or profit, on a forecast basis.

CPUC Base Rates

Base rates for SCE's generation and distribution functions provide a rate of return and are authorized by the CPUC through triennial GRC proceedings. The CPUC sets an annual revenue requirement for the base year which is made up of the carrying cost on capital investment (depreciation, return and taxes), plus the authorized level of operation and maintenance expense. The return is established by multiplying an authorized rate of return, determined in the separate cost of capital proceedings (as discussed below), by the generation and distribution rate base. In the GRC proceedings, the CPUC also approves capital spending on a forecast basis. Adjustments to the revenue requirement for the remaining two years of a typical three-year GRC cycle are requested, based on criteria established in the GRC proceeding, which generally, among other items, include annual allowances for escalation in operation and maintenance costs, forecasted changes in capital-related investments and the timing and number of expected nuclear refueling outages. SCE's most recent GRC decision for the 2009-2011 period was issued in March 2009 and was effective as of January 1, 2009. SCE expects to begin proceedings for the 2012 GRC in the third quarter of 2010. As part of the GRC, the CPUC has authorized a revenue decoupling mechanism, which allows for the difference between the revenue authorized and the actual volume of electricity sales to be collected from or refunded to ratepayers. Accordingly, SCE does not bear the volumetric risk related to electricity sales.

The CPUC regulates SCE's capital structure and authorized rate of return. SCE's current authorized capital structure is 48% common equity, 43% long-term debt and 9% preferred equity. SCE's current authorized cost of capital consists of: cost of long-term debt of 6.22%, authorized cost of preferred equity of 6.01% and authorized return on common equity of 11.5%. In 2008, the CPUC approved a multi-year cost of capital mechanism, which allows for annual adjustments if certain thresholds are reached. SCE's earnings may be impacted when actual financing costs are above or below its authorized costs for long-term debt and preferred equity financings.

FERC Base Rates

Base rates for SCE's transmission functions provide a rate of return and are authorized by the FERC, in periodic proceedings that are similar to the CPUC GRC proceeding. Requested rate changes at the FERC are generally implemented before final approval of the application, with revenue collected prior to a final FERC decision being subject to refund. FERC-approved base rate revenues that vary from forecast are not subject to balancing account mechanisms, or otherwise recoverable or refundable and will therefore impact earnings.

Cost-Recovery Rates

Cost-recovery mechanisms allow SCE to recover its costs, but do not allow a return or profit. These mechanisms are used to recover SCE's costs of fuel, purchased-power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation

Table of Contents

and maintenance expenses, and depreciation expense related to certain projects. Although the CPUC authorizes balancing account mechanisms for such costs to refund or recover any differences between forecasted and actual costs, under- or over-collections in these balancing accounts do impact cash flows and can build rapidly.

The CPUC also uses a mechanism known as a "balancing account" to eliminate the effect on earnings that differences in revenue resulting from actual and forecast electricity sales may have. Under this mechanism, the difference in revenue between actual and forecast electricity sales is recovered from or refunded to ratepayers and therefore does not impact SCE's earnings.

SCE's balancing account for fuel and power procurement-related costs is established under the Energy Resource Recovery Account ("ERRA") Mechanism. SCE files annual forecasts of the costs that it expects to incur during the following year and sets rates using forecasts. The CPUC has established a "trigger" mechanism for the ERRA balancing account that allows for a rate adjustment if the balancing account over-collection or under-collection exceeds 5% of SCE's prior year's generation revenue.

The majority of costs eligible for recovery through cost-recovery rates are subject to CPUC reasonableness reviews, and thus could negatively impact earnings and cash flows if found to be unreasonable and disallowed.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

The CPUC has adopted an Energy Efficiency Risk/Reward Incentive Mechanism which allows for both financial incentives and economic penalties based on SCE's performance toward meeting goals set by the CPUC for energy efficiency. Under this mechanism, SCE has the opportunity to earn an incentive if it achieves 85% or more of its energy efficiency goals for the three year period. Economic penalties would be imposed in the event SCE achieves less than 65% of its goals. The mechanism allows for two annual progress payments, subject to holdback percentages, for progress towards meeting the goals and a third payment for final performance on the goals, which includes the payment of any holdbacks. SCE may retain the first and second progress payments as long as it meets a minimum of 65% of the goals. If SCE does not meet the 65% level, the amount of the progress payments and economic penalties would be deducted from future incentive payments. Both incentives and economic penalties for each three-year period are capped at $200 million.

In January 2009, the CPUC issued a new rulemaking intended to review the framework of the Energy Efficiency Risk/Reward Incentive Mechanism. The CPUC has yet to release a Decision on a new framework.

CDWR-Related Rates

As a result of the California energy crisis, in 2001 the California Department of Water Resources ("CDWR") entered into contracts to purchase power for sale at cost directly to SCE's retail customers and issued bonds to finance those power purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of the Investor-Owned Utilities. SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges

Table of Contents

and direct access exit fees. The CDWR-related charges and a portion of direct access exit fees that are remitted directly to the CDWR are not recognized as electric utility revenue by SCE and therefore have no impact on SCE's earnings; however, they do impact customer rates.

Competition

Because SCE is an electric utility company operating within a defined service territory pursuant to authority from the CPUC, SCE faces competition only to the extent that federal and California laws permit other entities to provide electricity and related services to customers within SCE's service territory. While California law provides only limited opportunities for customers to choose to purchase power directly from an energy service provider other than SCE, a California law was adopted in 2009 that permits a limited, phased-in expansion of customer choice (direct access) for nonresidential customers. SCE also faces some competition from cities and municipal districts that create municipal utilities or community choice aggregators. In addition, customers may install their own on-site power generation facilities.

Competition with SCE is conducted mainly on the basis of price, as customers seek the lowest cost power available. The effect of competition on SCE generally is to reduce the number of customers purchasing power from SCE, but those customers typically continue to utilize and pay for SCE's transmission and distribution services.

In the area of transmission infrastructure, SCE may experience increased competition from merchant transmission providers.

Purchased Power and Fuel Supply

SCE obtains the power needed to serve its customers from its generating facilities and from purchases from qualifying facilities ("QFs"), independent power producers, renewable power producers, the CAISO, and other utilities. In addition, power is provided to SCE's customers through purchases by the CDWR under contracts with third parties. Sources of power to serve SCE's customers during 2009 were approximately: 44% purchased power; 23% CDWR; and 33% SCE-owned generation.

Natural Gas Supply

SCE requires natural gas to meet contractual obligations for power tolling agreements (power contracts in which SCE has agreed to provide the natural gas needed for generation under those power contracts) and to serve demand for gas at Mountainview and SCE's peaker plants, which are supplemental plants that only operate when demand for power is high. All of the physical gas purchased by SCE in 2009 was purchased through competitive bidding.

Table of Contents

Nuclear Fuel Supply

For San Onofre Units 2 and 3, contractual arrangements are in place covering 100% of the projected nuclear fuel requirements through the years indicated below:

Uranium concentrates	2020
Conversion	2020
Enrichment	2020
Fabrication	2015

For Palo Verde, contractual arrangements are in place covering 100% of the projected nuclear fuel requirements through the years indicated below:

Uranium concentrates	2010
Conversion	2011
Enrichment	2013
Fabrication	2016

Spent Nuclear Fuel

Information about Spent Nuclear Fuel appears in "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

Coal Supply

On January 1, 2005, SCE and the other Four Corners participants entered into a Restated and Amended Four Corners Fuel Agreement with the BHP Navajo Coal Company, under which coal will be supplied to Four Corners Units 4 and 5 until July 6, 2016. The Restated and Amended Agreement contains an option to extend for not less than five additional years or more than 15 years.

CAISO Wholesale Energy Market

In California and other states, wholesale energy markets exist through which competing electricity generators offer their electricity output to electricity retailers. Each state's wholesale electricity market is generally operated by its state ISO or a regional RTO. California's wholesale electricity market is operated by the CAISO. In 2006, the CAISO began its Market Redesign and Technology Upgrade ("MRTU") program to redesign and upgrade the wholesale energy market across its controlled grid. The MRTU market design allows the CAISO to schedule power in hourly increments with hourly prices through a real-time and day-ahead market that combines energy, ancillary services, unit commitment and congestion management. These MRTU features became effective in March 2009 and SCE began participating in the day-ahead and real-time markets for the sale of its generation and purchases of its load requirements.

The MRTU structure uses a nodal locational pricing model, which sets wholesale electricity prices at 3,000 different system points (nodes) that reflect local generation and delivery costs, as opposed to the previous system of three broad zonal prices. Generally, SCE schedules its

Table of Contents

electricity generation to serve its load but when it has excess generation or the market price of power is more economic than its own generation, SCE may sell power from utility-owned generation assets and existing power procurement contracts on, or buy generation and/or ancillary services to meet its load requirements from, the day-ahead market. SCE will offer to buy its generation at nodes near the source of the generation, but will take delivery at nodes throughout SCE's service territory. Congestion may occur when available energy cannot be delivered to all loads due to transmission constraints, which results in transmission congestion charges and differences in prices at various nodes. The CAISO also offers congestion revenue rights or CRRs, a commodity that entitles the holder to receive (or pay) the value of transmission congestion between specific nodes, acting as an economic hedge against transmission congestion charges.

Properties

SCE supplies electricity to its customers through extensive transmission and distribution networks. Its transmission facilities, which are located primarily in California but also in Nevada and Arizona, deliver power from generating sources to the distribution network and consist of 33 kV, 55 kV, 66 kV, 115 kV, 161 kV; 220 kV and 500 kV lines; and 893 substations. SCE's distribution system, which takes power from substations to customers, includes over 70,000 circuit miles of overhead lines, 43,500 circuit miles of underground lines, 1.46 million poles, over 720 distribution substations, approximately 715,600 transformers, and 813,000 area lights and streetlights, all of which are located in California.

Table of Contents

SCE owns the following generating facilities (and operates all of these facilities except Palo Verde and Four Corners, which are operated by Arizona Public Service Company ("APS")):

Generating Facility	Location (in CA, unless otherwise noted)	Fuel Type	SCE's Ownership Interest (%)	Net Physical Capacity (in MW)	SCE's Capacity pro rata share (in MW)
San Onofre Nuclear Generating Station	South of San Clemente	Nuclear	78.21%	2,150	1,760
Hydroelectric Plants (36)	Various	Hydroelectric	100%	1,176	1,176
Pebbly Beach Generating Station	Catalina Island	Diesel	100%	9	9
Mountainview	Redlands	Natural Gas	100%	1,050	1,050
Center Peaker	Norwalk	Gas fueled Combustion Turbine	100%	49	49
Mira Loma Peaker	Ontario	Gas fueled Combustion Turbine	100%	49	49
Grapeland Peaker	Rancho Cucamonga	Gas fueled Combustion Turbine	100%	49	49
Barre Peaker	Stanton	Gas fueled Combustion Turbine	100%	49	49
Palo Verde Nuclear Generating Station	Phoenix, AZ	Nuclear	15.8%	3,739	591
Four Corners Units 4 and 5	Farmington, NM	Coal-fired	48%	1,500	720
Total				9,820	5,502

San Onofre, Four Corners, certain of SCE's substations, and portions of its transmission, distribution and communication systems are located on lands owned by the United States or others under licenses, permits, easements or leases, or on public streets or highways pursuant to franchises. Certain of the documents evidencing such rights obligate SCE, under specified circumstances and at its expense, to relocate such transmission, distribution, and communication facilities located on lands owned or controlled by federal, state, or local governments.

Thirty-one of SCE's 36 hydroelectric plants and related reservoirs, are located in whole or in part on U.S.-owned lands pursuant to 30- to 50-year FERC licenses that expire at various times between 2010 and 2040. Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire projects upon payment of specified compensation. When existing licenses expire, the FERC has the authority to issue new licenses to third parties that have filed competing license applications, but only if their license

Table of Contents

application is superior to SCE's and then only upon payment of specified compensation to SCE. New licenses issued to SCE are expected to contain more restrictions and obligations than the expired licenses because laws enacted since the existing licenses were issued require the FERC to give environmental objectives greater consideration in the licensing process.

Substantially all of SCE's properties are subject to the lien of a trust indenture securing first and refunding mortgage bonds, of which approximately $6.4 billion in principal amount was outstanding on February 26, 2010.

SCE's rights in Four Corners, which is located on land of the Navajo Nation under an easement from the United States and a lease from the Navajo Nation, may be subject to possible defects. These defects include possible conflicting grants or encumbrances not ascertainable because of the absence of, or inadequacies in, the applicable recording law and record systems of the Bureau of Indian Affairs and the Navajo Nation, the possible inability of SCE to resort to legal process to enforce its rights against the Navajo Nation without Congressional consent, the possible impairment or termination under certain circumstances of the easement and lease by the Navajo Nation, Congress, or the Secretary of the Interior, and the possible invalidity of the trust indenture lien against SCE's interest in the easement, lease, and improvements on Four Corners.

Insurance

SCE has property and casualty insurance policies, which include excess liability insurance covering liabilities to third parties for bodily injury or property damage resulting from operations.

Severe wildfires in California have given rise to large damage claims against California utilities. Additionally, California law includes a doctrine of inverse condemnation that imposes strict liability (including liability for a claimant's attorneys' fees) for fire damage caused to private property by a utility's electric facilities that serve the public. These damage claims and the related doctrine may affect SCE's liability insurance levels and cost. On September 1, 2009, SCE renewed its insurance coverage, which included coverage for wildfire liabilities up to a reduced limit of $500 million (with an increased self-insured retention of $10 million per wildfire occurrence). Various coverage limitations within the policies that make up the insurance coverage could result in substantially higher self-insured costs in the event of multiple wildfire occurrences during the policy period (September 1, 2009 to August 31, 2010). SCE may experience further coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.

Seasonality

For a discussion of the seasonality of electric utility revenues, see "Electric Utility Results of Operations Supplemental Operating Revenue Information" in the MD&A.

Table of Contents

EDISON MISSION GROUP INC.

Regulation

U. S. Federal Energy Regulation

Federal Power Act

The Federal Power Act ("FPA") grants the FERC exclusive jurisdiction over the rates, terms and conditions of wholesale sales of electricity and transmission services in interstate commerce (other than transmission that is "bundled" with retail sales), including ongoing, as well as initial, rate jurisdiction. This jurisdiction allows the FERC to revoke or modify previously approved rates after notice and opportunity for hearing. These rates may be based on a cost-of-service approach or, in geographic and product markets determined by the FERC to be workably competitive, may be market based.

The FPA also grants the FERC jurisdiction over the sale or transfer of specified assets, including wholesale power sales contracts and generation facilities, and in some cases, jurisdiction over the issuance of securities or the assumption of specified liabilities and some interlocking directorates. Dispositions of EME's jurisdictional assets or certain types of financing arrangements may require FERC approval.

Deregulation of the electric generating sector began with the enactment of PURPA, which established a regulatory scheme for certain qualifying facilities. Most qualifying facilities, as that term is defined in PURPA, are exempt from the ratemaking and several other provisions of the FPA. It was further expanded with the passage of the Energy Policy Act of 1992, which established a regulatory scheme for EWGs and foreign utility companies. EWGs are subject to the FPA and to the FERC's ratemaking jurisdiction thereunder, but the FERC typically grants EWGs the authority to sell power at market-based rates to purchasers which are not affiliated electric utility companies as long as the absence of market power is shown. More recently, in EPAct 2005, the U.S. Congress recognized that a significant market for electric power generated by independent power producers, such as EME, has developed in the United States and indicated that competitive wholesale electricity markets have become accepted as a fundamental aspect of the electricity industry.

Each of EME's U.S. generating facilities has either been determined by the FERC to qualify as a qualifying facility, or the subsidiary owning the facility has been determined to be an EWG. In addition, EME's power marketing subsidiaries, including EMMT, have been authorized by the FERC to make wholesale market sales of power at market-based rates and are subject to the FERC ratemaking regulation under the FPA.

Public Utility Regulatory Policies Act of 1978

PURPA provides two primary benefits to qualifying facilities. First, all cogeneration facilities that are qualifying facilities are exempt from certain provisions of the FPA and regulations of the FERC thereunder. Second, the FERC regulations promulgated under PURPA initially required electric utilities to purchase electricity generated by qualifying facilities at a price based on the purchasing utility's avoided cost and to sell back up power to the qualifying

Table of Contents

facility on a nondiscriminatory basis. EPAct 2005 provides for the elimination of a utility's obligation to purchase power from qualifying facilities at its avoided cost if the FERC determines that the relevant market meets certain conditions for competitive, nondiscriminatory access. The FERC's regulations also permit qualifying facilities and utilities to negotiate agreements for utility purchases of power at prices different from the utility's avoided costs, but do not require utilities to purchase power at such prices.

Several of EME's projects, including the Big 4 projects, are qualifying cogeneration facilities. Qualifying cogeneration facilities must produce electricity and useful thermal energy for an industrial or commercial process or heating or cooling applications in certain proportions to the facility's total energy output, and must meet certain efficiency standards. If one of the projects in which EME has an interest were to lose its qualifying facility status, the project would no longer be entitled to the qualifying facility-related exemptions from regulation and could become subject to rate regulation by the FERC under the FPA and additional state regulation. Loss of qualifying facility status could also trigger defaults under covenants to maintain qualifying facility status in the project's power sales agreements, steam sales agreements and financing agreements and result in refund claims from utility customers, termination, penalties or acceleration of indebtedness under such agreements. EME endeavors to monitor regulatory compliance by its qualifying facility projects in a manner that minimizes the risks of losing these projects' qualifying facility status.

Transmission of Wholesale Power

Generally, projects that sell power to wholesale purchasers other than the local utility to which the project is interconnected require the transmission of electricity over power lines owned by others. The prices and other terms and conditions of transmission contracts are regulated by the FERC when the entity providing the transmission service is subject to FERC jurisdiction pursuant to the FPA.

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

State Energy Regulation Illinois Power Procurement

The Illinois Power Agency Act regulates the procurement of power by Commonwealth Edison and the Ameren Illinois utilities for their bundled-rate customers. In June 2009, the newly created Illinois Power Agency became responsible for the administration, planning and procurement of power for Commonwealth Edison and the Ameren Illinois utilities' bundled-rate customers using a portfolio-managed approach that is to include competitively procured standard wholesale products and renewable energy resources.

The Illinois Commerce Commission, which continues in its role of oversight and approval of the power planning and procurement for utilities' bundled retail customers, approved in January 2009, a procurement plan for 2009 that was proposed by the Illinois Power Agency. The plan, which was based on five-year demand forecasts, uses a laddered procurement strategy for the 2009-2014 period. In 2009, the Illinois Power Agency acquired through a single request for proposals roughly one third of the forecasted demand for bundled load for Commonwealth Edison and the Ameren Illinois utilities. Renewable requirements, in the first year, were purchased by way of one-year renewable energy credits; longer contracts may be included in future procurements if required by law or if approved by the Illinois Commerce Commission. In December 2009, the Illinois Power Agency's procurement plan for supply for the utilities' bundled customers for the 2010-2015 period was approved by the Illinois Commerce Commission.

Markets for Generation

The United States electric industry, including companies engaged in providing generation, transmission, distribution and retail sales and service of electric power, has undergone significant deregulation over the last three decades, which has led to increased competition, especially in the generation sector. See further discussion of regulations under " Regulation of EME United States Federal Energy Regulation."

In areas where ISOs and RTOs have been formed, market participants have open access to transmission service typically at a system-wide rate. ISOs and RTOs may also operate real-time and day-ahead energy and ancillary service markets, which are governed by FERC-approved tariffs and market rules. The development of such organized markets into which independent power producers are able to sell has reduced their dependence on bilateral contracts with electric utilities.

In various regional wholesale power markets, market administrators and independent market monitors have acknowledged that generators historically have not been provided adequate compensation in the energy markets to avoid the retirement of existing generation or provide adequate financial incentives to attract new investment when needed to ensure system reliability. As a result, capacity markets have emerged to provide additional financial incentives for electric capacity by compensating supply resources for the capability to supply electricity when needed, and demand resources, for electricity they avoid using. Capacity markets are expected to provide additional revenues for independent power producers.

Wholesale Markets

EME's largest power plants are its fossil fuel power plants located in Illinois, which are collectively referred to as the Midwest Generation plants, and the Homer City electric generating station located in Pennsylvania, which is referred to as the Homer City facilities. Collectively, both the Midwest Generation plants and Homer City facilities are referred to as the fossil-fueled facilities in this annual report. The fossil-fueled facilities are "merchant" generating stations that sell power primarily into PJM, an RTO which includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PJM operates a wholesale spot energy market and determines the market-clearing price for each hour based on bids submitted by participating generators indicating the minimum prices at which a bidder is willing to dispatch energy at various incremental generation levels. PJM conducts both day-ahead and real-time energy markets. PJM's energy markets are based on locational marginal pricing, which establishes hourly prices at specific locations throughout

Table of Contents

PJM by considering a number of factors, including generator bids, load requirements, transmission congestion and transmission losses. It can also be affected by, among other things, price caps and other market rules intended to facilitate competition and discourage the exercise of market power.

PJM requires all load-serving entities to maintain prescribed levels of capacity, including a reserve margin, to ensure system reliability. PJM also determines the amount of capacity available from each generator and operates capacity markets. PJM's capacity markets have a single market-clearing price. In June 2007, PJM implemented the reliability pricing model ("RPM") for capacity, under which capacity commitments are made in advance to provide a long-term pricing signal for capacity resources. The RPM is intended to provide a mechanism for PJM to meet the region's need for generation capacity, while allocating the cost to load-serving entities through a locational reliability charge. PJM also implemented marginal losses for transmission for its competitive wholesale electric market.

Load-serving entities and generators, such as EME's subsidiaries, Midwest Generation (with respect to the Midwest Generation plants) and Homer City (with respect to the Homer City facilities), may participate in PJM's capacity markets or transact capacity sales on a bilateral basis. Sales may also be made from PJM into the Midwest ISO ("MISO") RTO, which includes all or parts of Illinois, Wisconsin, Indiana, Michigan, Ohio, and other states in the region, and into the New York ISO ("NYISO"), which controls the transmission grid and energy and capacity markets for New York State.

Two of EME's wind projects sell electricity into RTOs as merchant generators. The Lookout wind project sells power into the PJM market, and the Goat Wind wind project sells power into the Electric Reliability Council of Texas market. The rest of EME's wind power generation facilities currently sell capacity, energy and/or ancillary services pursuant to bilateral contracts with electric utilities, regional cooperatives and public power authorities.

Competition

EME is subject to intense competition from energy marketers, investor-owned utilities, government-owned power agencies, industrial companies, financial institutions, and other independent power producers. Some of EME's competitors have a lower cost of capital than most independent power producers and, in the case of utilities, are often able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation without relying exclusively on market clearing prices to recover their investments. These companies may also have competitive advantages as a result of their scale, the location of their generation facilities, and their contractual arrangements with affiliated entities.

Environmental regulations, particularly those that impose stringent state specific emission limits, could put EME's coal-fired plants at a disadvantage compared with competing power plants operating in nearby states and subject only to federal emission limits. Potential future climate change regulations could also put EME's coal-fired plants at a disadvantage compared to both power plants utilizing other fuels and utilities that may be able to recover climate change compliance costs through rate mechanisms. In addition, the ability of EME's fossil fuel-fired plants to compete may be affected by governmental and regulatory activities

Table of Contents

designed to support the construction and operation of power generation facilities fueled by renewable energy sources.

Marketing and Trading Activities

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

Marketing EMMT engages in the sale of energy and capacity and the purchase of fuels, including coal, natural gas and fuel oil, through intercompany contracts with EME's subsidiaries that own or lease the fossil-fueled facilities and EME's merchant wind energy facilities. EME uses derivatives to reduce its exposure to market risks that arise from fluctuations in the prices of electricity, capacity, fuel, emission allowances, and transmission rights. The objective of these activities is to sell the output of the power plants on a forward basis or to hedge the risk of future changes in prices, thereby increasing the predictability of earnings and cash flows. Hedging activities include on-peak and off-peak periods and may include load service requirements contracts with local utilities. Transactions entered into related to hedging activities are designated separately from EMMT's trading activities and are recorded in what EMMT calls its hedge book. Not all contracts entered into by EMMT for hedging purposes qualify as hedges for accounting purposes.

Trading As an extension of its marketing and hedging activities, EMMT seeks to generate trading profits from volatility in the price of electricity, capacity, fuels, and transmission congestion by buying and selling contracts in wholesale markets under limitations approved by EME's risk management committee.

Table of Contents

Properties

Existing Power Plants

As of December 31, 2009, EME's operations consisted of ownership or leasehold interests in the following operating projects:

Power Plants	Location	Primary Electric Purchaser[2]	Fuel Type	EME's Ownership Interest	Net Physical Capacity (in MW)	EME's Capacity Pro Rata Share (in MW)
MERCHANT POWER PLANTS						
Midwest Generation plants[1]	Illinois	PJM	Coal	100%	5,471	5,471
Midwest Generation plants[1]	Illinois	PJM	Oil/Gas	100%	305	305
Homer City facilities[1]	Pennsylvania	PJM	Coal	100%	1,884	1,884
Goat Wind	Texas	ERCOT	Wind	99.9%[3]	150	150
Lookout	Pennsylvania	PJM	Wind	100%	38	38
CONTRACTED POWER PLANTS Domestic						
Natural Gas						
Big 4 Projects						
Kern River[1]	California	SCE	Natural Gas	50%	300	150
Midway-Sunset[1]	California	SCE	Natural Gas	50%	225	113
Sycamore[1]	California	SCE	Natural Gas	50%	300	150
Watson	California	SCE	Natural Gas	49%	385	189
Westside Projects[1]						
Coalinga	California	PG&E	Natural Gas	50%	38	19
Mid-Set	California	PG&E	Natural Gas	50%	38	19
Salinas River	California	PG&E	Natural Gas	50%	38	19
Sargent Canyon	California	PG&E	Natural Gas	50%	38	19
March Point[4]	Washington	PSE	Natural Gas	50%	140	70
Sunrise[1]	California	CDWR	Natural Gas	50%	572	286
Renewable Energy						
Buffalo Bear	Oklahoma	WFEC	Wind	100%	19	19
Crosswinds	Iowa	CBPC	Wind	99%[3]	21	21
Elkhorn Ridge	Nebraska	NPPD	Wind	67%	80	53
Forward	Pennsylvania	CECG	Wind	100%	29	29
Hardin	Iowa	IPLC	Wind	99%[3]	15	15
High Lonesome	New Mexico	APSC	Wind	100%	100	100
Jeffers	Minnesota	NSPC	Wind	99.9%[3]	50	50
Minnesota Wind projects[5]	Minnesota	NSPC/IPLC	Wind	75-99%[3]	83	75
Mountain Wind I	Wyoming	PC	Wind	100%	61	61
Mountain Wind II	Wyoming	PC	Wind	100%	80	80

Odin	Minnesota	MRES	Wind	99.9%[3]	20	20
San Juan Mesa	New Mexico	SPS	Wind	75%	120	90
Sleeping Bear	Oklahoma	PSCO	Wind	100%	95	95
Spanish Fork	Utah	PC	Wind	100%	19	19
Storm Lake[1]	Iowa	MEC	Wind	100%	109	109
Wildorado	Texas	SPS	Wind	99.9%[3]	161	161
Huntington Waste-to-Energy	New York	LIPA	Biomass	38%	25	9
Coal						
American Bituminous[1]	West Virginia	MPC	Waste Coal	50%	80	40
CONTRACTED POWER PLANTS International						
Doga[1]	Turkey	TEDAS	Natural Gas	80%	180	144
Total					11,269	10,072

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

Table of Contents

2 Electric purchaser abbreviations are as follows:

APSC	Arizona Public Service Company	NSPC	Northern States Power Company
CBPC	Corn Belt Power Cooperative	PC	PacifiCorp
CDWR	California Department of Water Resources	PG&E	Pacific Gas & Electric Company
CECG	Constellation Energy Commodities Group, Inc.	PJM	PJM Interconnection, LLC
ERCOT	Electric Reliability Council of Texas	PSCO	Public Service Company of Oklahoma
IPLC	Interstate Power and Light Company	PSE	Puget Sound Energy, Inc.
LIPA	Long Island Power Authority	SCE	Southern California Edison Company
MEC	Mid-American Energy Company	SPS	Southwestern Public Service
MPC	Monongahela Power Company	TEDAS	Türkiye Elektrik Dagitim Anonim Sirketi
MRES	Missouri River Energy Services	WFEC	Western Farmers Electric Cooperative
NPPD	Nebraska Public Power District		

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

4 EME sold its ownership interest in the March Point project to its partner, Equilon Enterprises, LLC in February 2010.

5 Comprised of seven individual wind projects.

Projects under Construction

As of December 31, 2009, EME had the projects described below under construction.

Big Sky Wind Project

EME owns 100% of Big Sky Wind, LLC, which owns a 240 MW wind project under construction in Illinois, which EME refers to as the Big Sky wind project. Construction of this project commenced during the fourth quarter of 2009 and is scheduled for completion in late 2010. The project plans to sell electricity into the PJM market as a merchant generator or to third-party customers under power sales contracts.

Cedro Hill Wind Project

EME owns 100% of Cedro Hill Wind, LLC, which owns a 150 MW wind project under construction in Texas, which EME refers to as the Cedro Hill wind project. Construction of this project commenced during the fourth quarter of 2009 and is scheduled for completion in early 2011. The project has entered into a 20-year power purchase agreement with the City of San Antonio.

Renewable Development Activities

EME had a development pipeline of potential wind projects with projected installed capacity of approximately 4,000 MW at January 31, 2010. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. As of December 31, 2009, EME had commitments to purchase 183 wind turbines (349 MW) and had 67 wind turbines (163 MW) in storage to be used for future wind projects. Successful completion of development of a wind project depends upon obtaining permits and agreements necessary to support an investment and 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.

During 2008, EME had 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. During 2009, EME sold a number of solar projects under development to First Solar Electric and terminated the agreement.

Significant Customers

In the past three fiscal years, the fossil-fueled facilities sold electric power generally into the PJM market by participating in PJM's capacity and energy markets or by transact in capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 48%, 50% and 51% of EME's consolidated operating revenues for the years ended December 31, 2009, 2008 and 2007, respectively. For the years ended December 31, 2009 and 2008, a second customer, Constellation Energy Commodities Group, Inc. accounted for 16% and 10%, respectively, of EME's consolidated operating revenues. Sales to Constellation are primarily generated from the fossil-fueled facilities and consist of energy sales under forward contracts. In 2008 and 2007, EME also derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Midwest Generation plants to Commonwealth Edison under load requirements services contracts. By May 2009, all these contracts had expired. Sales under these contracts accounted for 12% and 19% of EME's consolidated operating revenues for the years ended December 31, 2008 and 2007, respectively.

Insurance

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

Seasonality

For a discussion of the seasonality of EME's Adjusted Operating income from its fossil-fueled facilities and unconsolidated affiliates, see "EMG: Results of Operations Adjusted Operating Income from Consolidated Operations" and " Adjusted Operating Income from Unconsolidated Affiliates" in the MD&A.

Table of Contents

Edison Capital

Energy and Infrastructure Investments

Edison Capital's energy and infrastructure investments are in the form of leveraged leases, partnership interests in international infrastructure funds and affordable housing projects in the United States.

As of December 31, 2009, Edison Capital is the lessor with an investment balance (including current lease receivable) of $184 million in the following leveraged leases:

Transaction	Asset	Location	Basic Lease Term Ends	Investment Balance (In millions)
Vidalia: selling power to Entergy Louisiana, City of Vidalia	192 MW hydro power plant	Vidalia, Louisiana	2020	$ 77
Beaver Valley: selling power to Ohio Edison Company, Centerior Energy Corporation	836 MW nuclear power plant	Shippingport, Pennsylvania	2017	$ 60
American Airlines	3 Boeing 767 ER aircraft	Domestic and international routes	2016	$ 47

Edison Capital's investments may be affected by the financial condition of other parties, the performance of assets, regulatory, economic conditions and other business and legal factors.

ENVIRONMENTAL REGULATION OF EDISON INTERNATIONAL AND SUBSIDIARIES

Because Edison International does not own or operate any assets, other than the stock of its subsidiaries, it does not have any direct environmental obligations or liabilities. However, legislative and regulatory activities by federal, state, and local authorities in the United States relating to energy and the environment impose numerous restrictions on the operation of existing facilities and affect the timing, cost, location, design, construction, and operation of new facilities by Edison International's subsidiaries, as well as the cost of mitigating the environmental impacts of past operations. Many of these laws, regulations and other activities affect both SCE and EME's subsidiaries, although not always to the same extent. The environmental regulations and other developments discussed below have the largest impact on fossil-fuel fired power plants, and therefore the discussion in this section focuses on regulations applicable to the states of California, New Mexico, Illinois, and Pennsylvania, where such facilities are located.

Additional information about environmental matters affecting Edison International, including projected environmental capital expenditures, is included in the MD&A under the heading " Environmental Capital Requirements, Commitments and Contingencies Compliance Costs" and in "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies Environmental Remediation."

Table of Contents

Climate Change

There have been a number of efforts at both the federal and state legislative and regulatory levels to adopt or enact regulations to reduce greenhouse gas emissions. Any climate change regulation or other legal obligation that would require substantial reductions in emissions of greenhouse gases or that would impose additional costs or charges for the emission of greenhouse gases could significantly increase the cost of generating electricity from fossil fuels, especially coal, as well as the cost of purchased power, which could adversely affect Edison International's business.

Federal Legislative/Regulatory Developments

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act. The bill, which was endorsed by Edison International, would establish a cap-and-trade system for greenhouse gas emissions commencing in 2012. Under the cap-and-trade system, a cap to reduce aggregate greenhouse gas emissions from all covered entities would be established and decline over time. Emitters of greenhouse gases would be required to have allowances for greenhouse gas emissions during a relevant measurement period. The bill would provide for stated portions of required allowances to be allocated free of charge in declining amounts over time. Emitters of greenhouse gases would have to purchase the remainder of their required allowances in the open market, although a portion may be provided by so-called offset credits (for alternative greenhouse gas reduction efforts). Similar legislation was introduced in the U.S. Senate in September 2009. Edison International cannot predict whether legislation imposing limits on greenhouse gas emissions in the U.S. will be passed in 2010, and the timing, content and potential effects on Edison International of any legislation that may be enacted remain uncertain.

Even if Congress does not pass legislation mandating greenhouse gas emissions reductions, regulatory developments under the Clean Air Act ("CAA") may also result in greenhouse gas emissions requirements that could affect Edison International's subsidiaries. In April 2007, the U.S. Supreme Court held, in *Massachusetts, et al. v. Environmental Protection Agency*, that greenhouse gases are "air pollutants" under the CAA and that that the US EPA has a duty to determine whether greenhouse gas emissions from new motor vehicles contribute to climate change or offer a reasoned explanation for its failure to make such a determination. In response to this decision, in December 2009, the US EPA issued a finding that certain greenhouse gases, including carbon dioxide, endanger the public health and welfare, which enables the US EPA to establish greenhouse gas emissions limits for new light-duty vehicles. It is expected that the US EPA will issue the final light-duty vehicle emissions limits in March 2010.

The December 2009 endangerment finding will trigger future regulation of stationary sources of greenhouse gases, such as power plants, which the US EPA plans to phase in beginning in 2011. In addition, when the regulation of greenhouse gases from light-duty vehicles is finalized, greenhouse gas emissions will become subject to review under the CAA's Prevention of Significant Deterioration ("PSD") (construction or modification of major sources) permit program. Sources subject to a PSD review for greenhouse gases would be required to use best available control technology ("BACT") to control greenhouse gas emissions. Because carbon dioxide is emitted in greater quantities than other CAA-regulated pollutants, regulating it under the PSD program would cover a large number of sources. To avoid the regulatory and enforcement consequences of such an outcome, in November 2009 the US EPA proposed a regulation, known as the "greenhouse gas tailoring rule." The greenhouse gas tailoring rule would redefine the PSD program to increase the threshold emission limit of carbon dioxide equivalents in a year from 250 tons to 25,000 metric tons. Whether or not this regulation is finalized, it is likely that EME's and SCE's fossil-fueled generating facilities would be major sources for purposes of the PSD programs. However, because the current PSD proposal affects only new or modified sources, it is not expected to have an immediate effect on EME's or SCE's existing generating plants. If EME or SCE are required to install pollution controls in the future or otherwise modify their operations in order to reduce carbon dioxide emissions, the impact will depend on the nature and timing of the controls to be applied, both of which remain uncertain. Edison International does not believe that currently there are commercially and technically feasible, full scale methods to control greenhouse gas emissions from its subsidiaries' existing fossil-fueled generating facilities.

State Legislative/Regulatory Developments

California has enacted two laws regarding greenhouse gas emissions. The first law, the California Global Warming Solutions Act of 2006 (also referred to as AB 32), establishes a comprehensive program to reduce greenhouse gas emissions. AB 32 requires the California Air Resources Board ("CARB") to develop regulations, potentially including market-based compliance mechanisms, targeted to reduce California's greenhouse gas emissions to 1990 levels by 2020. The CARB's mandatory program will commence in 2012 and will implement incremental reductions aimed at reducing greenhouse gas emissions to 1990 levels by 2020. The CARB has released preliminary draft regulations establishing a California cap-and-trade program, which include revisions to the CARB's mandatory greenhouse gas emissions reporting regulation and are expected to be finalized by the CARB in October 2010.

The second law, SB 1368, required the CPUC and the California Energy Commission ("CEC") to adopt greenhouse gas emission performance standards that restrict the ability of investor owned and publicly owned utilities, respectively, to enter into long-term arrangements for the purchase of electricity. The standards must equal the performance of a combined-cycle gas turbine generator. The standards that have been adopted prohibit California load-serving entities, including SCE, from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, which includes most coal-fired plants. Utility purchases of power generated by EME's facilities in California are subject to the emissions performance standards established in SB 1368. At this time, EME believes that all of its facilities in California meet the greenhouse gas emissions performance standard adopted under SB 1368, but EME will continue to monitor the regulations, as they are developed, for potential impact on its existing facilities and its projects under development.

SB 1368 also affects the ability of utilities to make long-term capital investments in generators that do not meet the emission performance standards. SB 1368 may prohibit SCE from making emission control expenditures at Four Corners.

Table of Contents

California law also requires SCE to increase its procurement of electricity generated from 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 such resources by no later than December 31, 2010 or such later date as flexible compliance requirements permit. In addition, in September 2009, Governor Schwarzenegger issued an executive order directing the CARB to adopt a regulation consistent with 33% of retail sellers' annual electricity sales being obtained from renewable energy sources by 2020. The executive order provides that the regulation may accelerate or expand the timeframe for compliance as well as increase the targeted percentage of annual electricity sales to be obtained from renewable resources, based on a thorough assessment of relevant factors.

Regional Initiatives

There are a number of regional initiatives relating to greenhouse gas emissions. Implementing regulations for such regional initiatives are likely to vary from state to state and may be more stringent and costly than federal legislative proposals currently being debated in Congress. It cannot yet be determined whether or to what extent any federal legislation would preempt regional or state initiatives, because these initiatives are in varying stages of development and implementation. If state and/or regional initiatives remain in effect after federal legislation is enacted, generators could be required to satisfy them in addition to federal standards.

Seven northeastern states have entered into a Memorandum of Understanding to establish a regional cap-and-trade greenhouse gas program for electric generators, referred to as the Regional Greenhouse Gas Initiative ("RGGI"). The RGGI states (now numbering 10) have passed laws and/or regulations to implement the RGGI program. Illinois and Pennsylvania are not signatories to the RGGI, although Pennsylvania participated in the process as an observer.

Illinois is a party to the Midwestern Greenhouse Gas Reduction Accord, by which six Midwestern states and the Canadian province of Manitoba agreed to develop regional greenhouse gas emission reduction goals within one year using a multi-sector cap-and-trade program to be implemented within 30 months. In June 2009, the Midwestern Greenhouse Gas Reduction Accord Advisory Group released its recommendations for emissions reduction targets and the design of a regional cap-and-trade program. The group is also drafting a framework for the cap-and-trade program that will serve as a basis for individual state legislative or regulatory action to implement the program.

Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec have launched the Western Climate Initiative to develop strategies to reduce greenhouse gas emissions in the region to 15% below 2005 levels by 2020. In September 2008, the Initiative partners released recommendations for a regional cap-and-trade program to help achieve that reduction goal. In February 2010, Arizona gave notice that it would not take part in the Western Climate Initiative's cap-and-trade program.

Table of Contents

Litigation Developments

In 2009, three courts issued decisions in cases involving the question of whether power plants and other large sources could constitute public nuisances, making the sources potentially liable for damages or other remedies.

In October 2009, a California federal district court dismissed the complaint that had been filed by the native Alaskan village of Kivalina and the Kivalina Tribe in February 2008 against 24 defendants, including Edison International, who directly or indirectly engaged in the electric generating, oil and gas, or coal mining lines of business. Plaintiffs had alleged greenhouse gas emissions from the defendants' business activities contributed to global warming impacts that are melting the Arctic sea ice that protects the village from winter storms and that the village would soon need to be abandoned or relocated at a cost of between $95 million and $400 million. The court dismissed the plaintiffs' federal nuisance claims stating that they were inappropriate for judicial resolution because they required policy choices that were reserved to the legislative or executive branches of the government (the "political question doctrine"). The court also held that the plaintiffs did not have standing under federal law to bring the case, in part because of the lack of connection between the defendants' conduct and the harm that plaintiffs alleged was occurring. The court also dismissed plaintiffs' state law nuisance claims, but without prejudice to those claims being re-filed in state court. The plaintiffs have appealed the dismissal order to the Ninth Circuit Court of Appeals.

In contrast to the district court decision in Kivalina, the U.S. Court of Appeals for the Second Circuit, in September 2009, and the U.S. Court of Appeals for the Fifth Circuit, in October 2009, reversed and remanded lower court decisions that had dismissed complaints (filed in New York and Mississippi, respectively), against electric utilities and others, for injunctive relief and/or damages allegedly arising as a result of greenhouse gas emissions. These courts held that plaintiffs had standing and that their claims (sounding in various common law theories, including public nuisance in the New York case and public nuisance, private nuisance, trespass and negligence in the Mississippi case) were not barred by the political question doctrine. Neither Edison International nor its subsidiaries was named as a defendant in the New York case. At the time the action was dismissed by the court in Mississippi, the plaintiffs were seeking to amend their complaint to include Edison International and several affiliates of Edison International, including EME and SCE, as defendants.

Each of these differing rulings remains subject to appeal, rehearing, or potential review by the U.S. Supreme Court, and thus the ultimate impact of these cases remains uncertain. In addition, Edison International cannot predict whether the appellate decisions will result in the filing of new actions with similar claims or whether Congress, in considering climate legislation, will address directly the availability of courts for these sorts of claims.

Table of Contents

Emissions Data Reporting

SCE's independently certified greenhouse gas emission data for 2007, as reported to the California Climate Action Registry, showed that SCE emitted approximately 6.8 million metric tons from SCE-owned generation. SCE's reported emissions are pro-rated to its ownership interests in the emitting facilities. EME's 2007 greenhouse gas emissions were approximately 47.4 million metric tons, although they were not independently verified. Beginning with 2008 data, SCE will be reporting to TCR (as described below) and to the CARB. Edison International and its subsidiaries will begin reporting 2010 data to the US EPA in 2011. SCE reported 2008 greenhouse gas emission data to the CARB in June 2009. The CARB reporting is done in three parts: greenhouse gas emissions from SCE-owned generation, sulfur hexafluoride (SF_6) emissions from SCE-owned or -operated equipment, and transaction reporting of MWhs purchased and resource types (from which the CARB calculates total greenhouse gas emissions). The CARB has not yet published its calculations on SCE's 2008 data.

Edison International became a founding reporter to The Climate Registry ("TCR"), formed in May 2008. TCR is a multi-national organization, which allows organizations to voluntarily inventory, verify, and publicly report their greenhouse gas emissions. Edison International filed initial emissions data for 2008 in September 2009 with TCR. This information did not cover all of Edison International's owned generation, as allowed under the TCR transitional reporter rules that apply for the first two years that an entity reports its emissions with TCR. Verified emissions data for Edison International is expected to be released publicly by TCR at the end of the second quarter of 2010.

In September 2009, the US EPA issued its Final Mandatory Greenhouse Gas Reporting Rule, which requires all energy sources within specified categories, including electric generation facilities, to begin monitoring greenhouse gas emissions in January 2010, and to submit annual reports to the US EPA by March 31 of each year, with the first report due on March 31, 2011.

Responses to Energy Demands and Future Greenhouse Gas Emission Constraints

Irrespective of the outcome of current federal or state legislative deliberations, Edison International believes that regulation of greenhouse gas emissions is likely to develop through increased costs, mandatory emission limits or other mechanisms, and that demand for energy from renewable sources will also continue to increase. As a result, SCE is creating a generation profile from wind, solar, geothermal, biomass and small hydro plants, that will be adaptable to a variety of regulatory and energy use environments. Its renewables portfolio of owned and procured sources currently consists of: 1,583 MW from wind, 956 MW from geothermal, 360 MW from solar, 178 MW from biomass, and 200 MW from small hydro. EME is developing several renewables projects and is the seventh largest wind power generator in the United States.

SCE has developed and promoted several energy efficiency and demand response initiatives in the residential market, including an ongoing meter replacement program to help reduce peak energy demand; a rebate program to encourage customers to invest in more efficient appliances; subsidies for purchases of energy efficient lighting products; appliance recycling

Table of Contents

programs; widely publicized tips to customers for saving energy; and a voluntary demand response program which offers customers financial incentives to reduce their electricity use. SCE is also replacing its electro-mechanical grid control systems with computerized devices that allow more effective grid management.

Corporate Governance Processes

The Boards of Directors of Edison International and SCE regularly receive reports from senior management regarding environmental issues that affect the companies, including climate change issues.

Air Quality

The CAA establishes a comprehensive program to protect and improve the nation's air quality by regulating certain air emissions from mobile and stationary sources. The states implement and administer many of these programs and may impose additional or more stringent requirements under the CAA scheme. The federal CAA, state clean air acts, and federal and state regulations implementing such statutes apply to plants owned by EME and SCE, as well as to plants from which SCE purchases power, but have their largest impact on the operation of coal-fired plants. The federal environmental regulations require states to adopt state implementation plans for certain pollutants, known as SIPs, which are equal to or more stringent than the federal requirements. These plans detail how the state will attain the standards that are mandated by the relevant law or regulation.

The CAA requires the US EPA to review the available scientific data for six criteria pollutants and establish a concentration level in the ambient air for those substances that is adequate to protect public health and welfare. These concentration levels are known as National Ambient Air Quality Standards, or NAAQS. The six criteria pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and sulfur dioxide.

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas), and must develop a SIP both to bring non-attainment areas into compliance with the NAAQS and to maintain good air quality in attainment areas. All SIPs are submitted to the US EPA for approval. If a state fails to develop adequate plans, the US EPA will develop and implement a plan. The attainment status of areas can change, and states may be required to develop new SIPs that address these changes. Many of EME's facilities are located in counties that have not attained NAAQS for ozone and fine particulate matter. NO_x emissions from power plants impact ambient air ozone levels and SO_2 emissions from power plants impact ambient air fine particulate matter levels.

As described further below, on December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at the Midwest Generation plants. The agreement requires Midwest Generation to achieve air emission reductions for NO_x and SO_2, and those reductions should contribute to or effect compliance with various existing US EPA ambient air quality standards. It is possible that if lower ozone, particulate matter, NO_x or SO_2 NAAQS are finalized by US EPA in the future, Illinois may implement regulations that are more stringent than those required by Midwest Generation's existing agreement with Illinois EPA.

Table of Contents

Nitrogen Oxide and Sulfur Dioxide

Clean Air Interstate Rule

The CAIR, issued by the US EPA on March 10, 2005, was intended to address ozone and fine particulate matter attainment issues by reducing regional NO_x and SO_2 emissions. The CAIR had mandated significant reductions in NO_x and SO_2 emission allowance caps under the CAA in the 28 eastern states and the District of Columbia where compliance with the national ambient air quality standards for ozone and fine particulate matter was at issue. There is substantial uncertainty as to how the US EPA will address the deficiencies identified in 2008 decisions by the U.S. Court of Appeals for the D.C. Circuit that resulted in the remand of the CAIR to the US EPA for the issuance of a revised rule. The CAIR will remain in effect until the US EPA issues a revised rule, which is currently expected to be proposed in 2010. As a result of the D.C. Circuit Court's decisions, it is unclear whether the US EPA will be able to design a cap-and-trade program for NO_x and SO_2 that is consistent with the CAA. It is also unclear whether existing SIPs in certain states, particularly Illinois and Pennsylvania, will be sufficient to comply with the CAA. The fossil-fueled facilities may be subject to additional requirements, which could result in increased capital expenditures and operating expenses to comply with a revised CAIR or alternative regulations under the CAA. In the case of the Midwest Generation plants, these new requirements could exceed those applicable under the CPS.

Proposed NAAQS for Sulfur Dioxide

In November 2009, the US EPA proposed a new one-hour NAAQS for SO_2. The new standard is proposed to be between 50 and 100 parts per billion. The US EPA is required by a consent decree to take final action by June 2, 2010. The proposed rule would require states to submit SIPs in 2014, with compliance by 2017.

Illinois

On December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at the Midwest Generation plants. The agreement has been embodied in an Illinois rule called the CPS. All of Midwest Generation's Illinois coal-fired electric generating units are subject to the CPS. The principal emission standards and control technology requirements for NO_x and SO_2 under the CPS are as described below:

NO_x Emissions Beginning in calendar year 2012 and continuing in each calendar year thereafter, Midwest Generation must comply with an annual and seasonal NO_x emission rate of no more than 0.11 lbs/million Btu. In addition to these standards, Midwest Generation must install and operate SNCR equipment on Units 7 and 8 at the Crawford Station by December 31, 2015.

SO_2 Emissions Midwest Generation must comply with an overall SO_2 annual emission rate beginning with 0.44 lbs/million Btu in 2013 and decreasing annually until it reaches 0.11 lbs/million Btu in 2019 and thereafter.

Table of Contents

Midwest Generation has not decided upon a particular combination of retrofits to meet the required step down in emission rates and continues to review alternatives, including interim compliance solutions. The CPS also specifies that specific control technologies are to be installed on some units by specified dates. In these cases, Midwest Generation must either install the required technology by the specified deadline or shut down the unit. The CPS also requires Midwest Generation to shut down Units 1 and 2 at the Will County Station by December 31, 2010.

During 2009, Midwest Generation also conducted tests of NOx removal technology based on SNCR that may be employed to meet CPS requirements. Based on this testing, Midwest Generation has concluded that installation of SNCR technology on multiple units will meet the NOx portion of the CPS. Capital expenditures for installation of SNCR equipment are expected to be approximately $88 million in 2010 and approximately $70 million in 2011.

Testing of FGD technology based on dry sodium sorbent injection demonstrated significant reductions in SO_2 when using the low-sulfur coal employed by Midwest Generation; however, further analysis and evaluation are required to determine the appropriate method to comply with the SO_2 portion of the CPS. Use of FGD technology based on injection of dry sodium sorbent in combination with Midwest Generation's use of low-sulfur coal is expected to require substantially less capital and installation time than dry scrubber technology, but would likely result in higher ongoing operating costs than dry scrubber technology and may consequently result in lower dispatch rates and reduced competitiveness. Midwest Generation may also combine the use of dry sorbent injection technology with upgrades to its particulate removal systems to meet environmental regulations.

Midwest Generation cannot predict what specific method of SO_2 removal will be used or the total costs that will be incurred to comply with the CPS. A decision whether or not to proceed with the above or other approaches to compliance remains subject to further analysis and evaluation of several factors, such as market conditions, regulatory and legislative developments, and forecasted capital and operating costs. Midwest Generation could elect to shut down units when required in order to comply with the SO_2 removal requirements of the CPS. Due to existing uncertainties about the factors noted above, Midwest Generation may defer final decisions about particular units as long as possible. Accordingly, final decisions on whether to install controls, the particular controls that will be installed and the resulting capital commitments may not occur for up to two years for some of the units and potentially later for others. Midwest Generation continues to evaluate various scenarios and cannot predict the extent of shut downs and retrofits or the particular combination of retrofits and shut downs it may ultimately employ to comply with the CPS.

Pennsylvania

The Homer City facilities were subject to CAIR during 2009 and complied with both the NO_x and SO_2 requirements using existing equipment and purchasing of SO_2 allowances. Pennsylvania adopted a state version of CAIR, which the US EPA approved in December 2009. Homer City expects to comply with the Pennsylvania CAIR, which is substantially similar to the federal CAIR, in the same manner in which it complies with the federal CAIR.

Table of Contents

Mercury Clean Air Mercury Rule

Until new federal standards are developed to replace the CAMR, EME will not be able to determine whether it will be necessary to undertake mercury emission control measures beyond those required by state regulations. The CAMR was established by the US EPA as an attempt to reduce mercury emissions from existing coal-fired power plants using a cap-and-trade program. EME's and SCE's coal-fired electric generating facilities (SCE currently has a 48% ownership interest in Units 4 and 5 at Four Corners) emit mercury and other regulated emissions. As a result of the decision by the U.S. Court of Appeals for the D.C. Circuit in February 2007 that rejected both the CAMR and the related decision by the US EPA to remove oil and coal-fired plants from the list of sources to be regulated under Section 112 of the CAA until CAMR is replaced by a new mercury rule, mercury regulation will come from state regulatory bodies. As described below, EME's coal-fired electric generating facilities are already subject to significant unit-specific mercury emission reduction requirements under Illinois and Pennsylvania law (although, as noted below, Pennsylvania's mercury regulations have been invalidated).

Illinois

Midwest Generation's compliance with the CPS supersedes the Illinois mercury regulations that would otherwise be applicable to the Midwest Generation plants. The CPS requires that, beginning in calendar year 2015, and continuing thereafter on a rolling 12-month basis, Midwest Generation must either achieve an emission standard of .008 lbs mercury/GWh gross electrical output or a minimum 90% reduction in mercury for each unit (except Unit 3 at the Will County Station, which shall be included in calendar year 2016).

In addition to these standards, Midwest Generation was required to install and operate carbon injection equipment on all operating units. Installation of the equipment was completed in 2009. Capital expenditures relating to these controls were $42 million. Midwest Generation will also be required to install cold side electrostatic precipitator or baghouse equipment on Unit 7 at the Waukegan Station by December 31, 2013, and on Unit 3 at the Will County Station by December 31, 2015.

Pennsylvania

Until new legislation is passed authorizing the adoption of revised mercury regulations, the Homer facilities will not be required to comply with Pennsylvania mercury limitations. The Pennsylvania Department of Environmental Protection ("PADEP") attempted to implement regulations reducing the mercury emissions at coal-fired power plants by 80% by 2010 and 90% by 2015, as embodied in the Pennsylvania CAMR SIP. The Pennsylvania Supreme Court upheld a decision by the Commonwealth Court declaring Pennsylvania's mercury rule unlawful, invalid and unenforceable, and enjoining Pennsylvania from continued implementation and enforcement of the rule.

Table of Contents

Ozone and Particulates

National Ambient Air Quality Standards

In September 2006, the US EPA issued a final rule that would significantly reduce the 24-hour fine particulate standard (from 65 ug/m3 to 35 ug/m3), but in February 2009, the U.S. Court of Appeals for the D.C. Circuit remanded the annual fine particulate matter standard to the US EPA for further review.

In March 2008, the US EPA issued a final rule revising the primary and secondary NAAQS for ozone, reducing the level of the 8-hour standard to 0.075 parts per million (ppm). In January 2010, the US EPA proposed revisions that would further lower the 8-hour primary ozone standard to a level in the range of 0.060 0.070 ppm and impose a cumulative, seasonal secondary standard in the range of 7 15 ppm-hours. Final standards are expected in August 2010. EME and SCE anticipate that any such further emission reduction obligations would not be imposed under this standard until 2014 at the earliest.

Illinois

The Illinois SIP for 8-hour ozone was submitted to the US EPA on March 18, 2009. The SIP for fine particulates was to be submitted to the US EPA by April 5, 2008, but is currently expected to be submitted in 2010. As the fine particulate and ozone standards are finalized, as described above, Illinois may be required to implement additional emission control measures to address emissions of NO_x, SO_2 and volatile organic compounds.

Pennsylvania

In August 2007, the US EPA accepted PADEP's maintenance plan, which indicated that the existing (and upcoming) regulations controlling emissions of volatile organic compounds and NO_x will result in continued compliance with the 8-hour ozone standard. However, in March 2009, the PADEP recommended to the US EPA that Indiana County (where the Homer City facilities are located) be designated non-attainment under the US EPA's 2008 revised 8-hour ozone standard. Until the US EPA completes its revision to the 8-hour ozone standard, redesignations are finalized, and additional regulations are developed to achieve attainment with the revised standard, EME will not know what specific requirements it will have to meet. However, EME expects that its currently installed SCRs will be capable of meeting these new requirements.

Effective April 1, 2009, the PADEP changed its air opacity policy, eliminating many exemptions and reducing the allowable exceedance rate to 0.5% of a unit's operating time. Homer City undertook optimization of unit ramp rates and combustion parameters at the Homer City facilities to reduce the deratings required to meet the opacity standards. Additional capital improvements may also be required. Homer City operated below the 0.5% exceedance rate during the second, third and fourth quarters of 2009.

With respect to fine particulates, in November 2009, the US EPA indicated that Indiana County, Homer City Township is not in compliance with applicable standards. The PADEP must now submit an updated SIP by November 13, 2012. EME cannot determine the potential effects of the SIP at this time.

Regional Haze

The regional haze rules under the CAA are designed to prevent impairment of visibility in certain federally designated areas. The goal of the rules is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions by 2064. Sources such as power plants that are reasonably anticipated to contribute to visibility impairment in Class I areas may be required to install best available retrofit technology ("BART") or implement other control strategies to meet regional haze control requirements. The US EPA issued a final rulemaking on regional haze in 2005 requiring emission controls that constitute BART for industrial facilities that emit air pollutants which reduce visibility by causing or contributing to regional haze. These amendments required states to develop implementation plans to comply with BART by December 2007, to identify the facilities that will have to reduce SO_2, NO_x and particulate matter emissions, and then to set BART emissions limits for those facilities. Failure to do so results in a federal implementation plan.

Illinois and Pennsylvania

Neither Illinois nor Pennsylvania has submitted a SIP that addresses regional haze issues under the CAA, and so, beginning on December 31, 2009 both states became subject to a two-year deadline after which a federal implementation plan will govern related emission issues. As a result of this uncertainty and the questions surrounding the CAIR program, EME cannot predict whether it will be required to install BART or implement other control strategies at the Midwest Generation plants and/or the Homer City facilities, what specific measures will be required or how much they will cost.

The CPS, discussed above in " Nitrogen Oxide and Sulfur Dioxide Illinois," addresses emissions reductions at BART affected sources. In Pennsylvania, the PADEP considers the CAIR to meet the BART requirements, and the Homer City facilities are only required to consider reductions in emissions of suspended particulate matter (PM10), which at this time are being evaluated by the state.

New Mexico

In relation to Four Corners, the US EPA requested that the Arizona Public Service Company ("APS") perform a regional haze BART analysis. APS submitted the analysis to the US EPA, proposing the installation of certain combustion control equipment as BART for Four Corners. However, the US EPA issued an advanced notice of proposed rulemaking that called for post-combustion controls in the form of selective catalytic reduction ("SCR") pollution control equipment. A final US EPA determination on this matter is expected in late 2010. Until the final determination is issued, SCE cannot predict what pollution control equipment will be required at Four Corners and thus cannot accurately estimate the expenditures that would be necessary for such equipment. In any case, due to the investment constraints of SB 1368, the California law on greenhouse gas emission performance standards discussed above in " Climate Change State Legislative/Regulatory Developments," SCE does not expect to be able to participate in any investment in SCR post-combustion controls or combustion controls at Four Corners. SCE thus does not expect to enter into any long-term ownership arrangements for its share of Four Corners Units 4 and 5 after the 2016 expiration of the current participant agreements due to the investment constraints of SB 1368.

New Source Review Requirements ("NSR")

The NSR regulations impose certain requirements on facilities, such as electric generating stations, if modifications are made to air emissions sources at the facility. Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address CAA compliance issues at the nation's coal-fired power plants. The strategy has included both the filing of suits against a number of power plant owners, and the issuance of administrative NOVs to a number of power plant owners alleging NSR violations.

Illinois and Pennsylvania

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that Midwest Generation and Commonwealth Edison violated various provisions of the NSR rules as well as state air regulations at the Midwest Generation plants. After attempts at settlement failed, on August 27, 2009, the US EPA and the State of Illinois filed a complaint in the Northern District of Illinois against Midwest Generation, but not Commonwealth Edison, based in part on the allegations in the NOV and alleging that construction projects undertaken prior to Midwest Generation's ownership violated various provisions of the NSR rules and Title V requirements. On June 12, 2008, Homer City received an NOV from the US EPA, which alleges that certain construction projects, all completed before Homer City acquired the Homer City facilities, violated various provisions of the NSR rules and Title V permit requirements. See "Item 3. Legal Proceedings Midwest Generation New Source Review Lawsuit" and " Homer City New Source Review Notice of Violation" for further discussion.

New Mexico

In April 2009, APS, as operating agent of Four Corners, received a US EPA request pursuant to Section 114 of the CAA for information about Four Corners. The US EPA requested information about Four Corners and its operations, including information about Four Corners capital projects from 1990 to the present. APS has responded to the US EPA request. SCE understands that in other cases the US EPA has utilized similar Section 114 letters for examining whether power plants have triggered NSR requirements under the CAA and are therefore potentially subject to more stringent air pollution control requirements. No NSR enforcement-related proceedings have been initiated by the US EPA with respect to Four Corners. SCE cannot predict the outcome of this inquiry.

Water Quality

Clean Water Act

Regulations under the federal Clean Water Act require permits for the discharge of pollutants into United States waters and permits for the discharge of storm water from certain facilities.

Table of Contents

The Clean Water Act also regulates the temperature of effluent discharges and the location, design, and construction of cooling water intake structures at generating facilities. California has a US EPA-approved program to issue individual or group (general) permits for the regulation of Clean Water Act discharges. California also regulates certain discharges not regulated by the US EPA.

In January 2007, the U.S. Court of Appeals for the Second Circuit rejected the US EPA rule on cooling water intake structures and remanded it to the US EPA. Among the key provisions remanded by the court were the use of cost-benefit analysis for determining the best technology available and the use of restoration to achieve compliance with the rule. On July 2007, the US EPA suspended the requirements for cooling water intake structures, pending further rulemaking. In April 2009, the U.S. Supreme Court reversed the Second Circuit and held that the US EPA may consider, but is not required to use, cost-benefit analysis in formulating regulations under Clean Water Act Section 316(b). The Court did not review the Second Circuit's rejection of the use of restoration as compliance with Section 316(b), which means the Second Circuit decision on this issue remains valid. The US EPA is currently rewriting the rule, and it is unknown whether revised regulations will use cost-benefit analysis.

EME has collected data at its potentially affected Midwest Generation plants in Illinois to begin determining what corrective actions might have been needed under the previous rule. Because there are no defined compliance targets absent a new rule, EME and SCE are reviewing a wide range of possible control technologies. Although the new rule could have a material impact on EME and SCE, until the final compliance criteria have been published, neither EME nor SCE can reasonably determine the financial impact.

Illinois

In October 2007, the Illinois EPA filed a proposed rule with the Illinois Pollution Control Board ("PCB") that would establish more stringent thermal and effluent water quality standards for the Chicago Area Waterway System and Lower Des Plaines River. Midwest Generation's Fisk, Crawford and Will County Stations use water from the Chicago Area Waterway System and its Joliet Station uses water from the Lower Des Plaines River for cooling purposes. The rule, if implemented, is expected to affect the manner in which those stations use water for station cooling.

The proposed rule is the subject of an administrative proceeding before the Illinois PCB and must be approved by the Illinois PCB and the Illinois Joint Committee on Administrative Rules as well as the US EPA. Hearings began in January 2008, and are continuing in 2010. Midwest Generation is a party in those proceedings. It is not possible to predict the timing for resolution of the proceeding, the final form of the rule, or how it would impact the operation of the affected stations; however, significant capital expenditures may be required depending on the form of the final rule.

Pennsylvania

The discharge from the treatment plant receiving the wastewater stream from EME's Unit 3 wet scrubbing system at the Homer City facilities has exceeded the stringent water-quality based limits for selenium in the station's NPDES permit. Homer City and the PADEP entered

Table of Contents

into a consent order and agreement related to selenium discharge, effective July 17, 2007, under which Homer City paid a civil penalty of $200,000 and agreed to install modifications to its wastewater system to achieve consistent compliance with discharge limits.

Prohibition on the Use of Ocean-Based Once-Through Cooling California

In June 2009 the California State Water Resources Control Board issued a draft "Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling." The Policy would establish closed-cycle wet cooling as the best technology available for retrofitting existing "once-through" cooled plants, such as SCE's San Onofre, which use ocean water for cooling purposes. If the draft policy is adopted, it may significantly impact both operations at San Onofre and SCE's ability to procure timely generating capacity from fossil-fuel plants that use ocean water in once-through cooling systems. It may also impact system reliability and the cost of electricity to the extent other coastal power plants in California are forced to shut down or limit operations. The Policy has the potential to adversely affect California's nineteen once-through cooled power plants, which provide over 21,000 MW of combined, in-state generation capacity, including over 9,100 MW of capacity interconnected within SCE's service territory.

Hazardous Substances and Hazardous Waste

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at that facility, and may be held liable for property damage, personal injury, natural resource damages, and investigation and remediation costs incurred by governmental entities and third parties in connection with these releases or threatened releases. Many of these laws, including the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, ("CERCLA"), impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under these laws to be strict and joint and several.

In connection with the ownership and operation of its facilities, Edison International may be liable for costs associated with hazardous waste compliance and remediation required by laws and regulations. Through an incentive mechanism, the CPUC allows SCE to recover in retail rates paid by its customers some of the environmental remediation costs at certain sites. Additional information about these laws and regulations appears in "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

Coal Combustion Wastes

US EPA regulations currently classify coal combustion wastes as solid wastes that are exempt from hazardous waste requirements. The exemption applies to fly ash, bottom ash, slag, and flue gas emission control wastes generated from the combustion of coal or other fossil fuels. The US EPA has studied coal combustion wastes extensively and in 2000 concluded that fossil fuel combustions wastes do not warrant regulation as a hazardous waste. The current classification of coal combustion wastes as exempt from hazardous waste requirements enables beneficial uses of coal combustion wastes, such as for cement production and fill materials. Midwest Generation currently provides a portion of its coal combustion wastes for beneficial uses. Midwest Generation is also examining the impact of current and proposed emission control technologies on ash quality for beneficial use.

The US EPA is expected to publish proposed regulations relating to coal combustion waste in 2010. Additional regulation of the storage, disposal and beneficial reuse of coal combustion waste could affect the management of such wastes and could require EME and SCE to incur additional capital and operating costs, with no assurance that the additional costs could be recovered. Additionally, SCE may be prohibited from making such expenditures under SB 1368, the California law on greenhouse gas emission performance standards (see " Climate Change State Legislative/Regulatory Developments" above for a description of SB 1368).

ITEM 1A. RISK FACTORS

RISKS RELATING TO EDISON INTERNATIONAL

Edison International's subsidiaries are subject to extensive environmental regulations that may involve significant and increasing costs and adversely affect them.

Edison International's subsidiaries are subject to extensive environmental regulation and permitting requirements that involve significant and increasing costs. SCE and EMG devote significant resources to environmental monitoring, pollution control equipment and emission allowances to comply with existing and anticipated environmental regulatory requirements. However, the current trend is toward more stringent standards, stricter regulation, and more expansive application of environmental regulations. The U.S. Congress is considering several proposals to regulate greenhouse gas emissions. The U.S. Environmental Protection Agency ("US EPA") has issued a finding that certain greenhouse gases endanger the public health and welfare and are air pollutants that are subject to the Clean Air Act. In addition, the attorneys general of several states, including California, certain environmental advocacy groups, and numerous state regulatory agencies in the United States have been focusing considerable attention on greenhouse gas emissions from coal-fired power plants and their potential role in climate change. The adoption of laws and regulations to implement greenhouse gas controls could adversely affect operations, particularly of the coal-fired plants. The continued operation of SCE and EMG facilities, particularly the coal-fired facilities, may require substantial capital expenditures for environmental controls. In addition, future environmental laws and regulations, and future enforcement proceedings by environmental authorities could affect the costs and the manner in which these subsidiaries conduct business. Current and future state laws and regulations in California also could increase the required amount of power that must be procured from renewable resources. Furthermore, changing environmental regulations could make some units uneconomical to maintain or operate. If the affected subsidiaries cannot comply with all applicable regulations, they could be required to retire or suspend operations at such facilities, or to restrict or modify the operations of these facilities, and their business, results of operations and financial condition could be adversely affected.

Edison International may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or to repay funds for an extended period to Edison International.

Edison International is a holding company and, as such, it has no operations of its own. Edison International's ability to meet its financial obligations and to pay dividends on its common stock at the current rate is primarily dependent on the earnings and cash flows of its subsidiaries and their ability to make upstream distributions or to repay funds to Edison International. Prior to funding Edison International, Edison International's subsidiaries have financial and regulatory obligations that must be satisfied, including, among others, debt service and preferred stock dividends. Financial market and economic conditions may have an adverse effect on Edison International's subsidiaries. See "Risks Relating to SCE" and "Risks Relating to EMG" below for further discussion.

RISKS RELATING TO SCE

Regulatory Risks

SCE's financial viability depends upon its ability to recover its costs in a timely manner from its customers through regulated rates.

SCE is a regulated entity subject to CPUC and FERC jurisdiction in almost all aspects of its business, including the rates, terms and conditions of its services, procurement of electricity for its customers, issuance of securities, dispositions of utility assets and facilities, aspects of project site identification and the operations of its electricity distribution systems. SCE's ongoing financial viability depends on its ability to recover from its customers in a timely manner its costs, including the costs of electricity purchased for its customers, through the rates it charges its customers as approved by the CPUC, and its ability to pass through to its customers in rates its FERC-authorized revenue requirements. SCE's financial viability also depends on its ability to recover through the rates it is allowed to charge an adequate return on capital, including long-term debt and equity. If SCE is unable to recover material amounts of its costs in rates in a timely manner or recover an adequate return on capital, its financial condition and results of operations could be materially adversely affected.

SCE's energy procurement activities are subject to regulatory and market risks that could adversely affect its financial condition and liquidity.

SCE obtains energy, capacity, renewable attributes and ancillary services needed to serve its customers from its own generating plants, as well as through contracts with energy producers and sellers. California law and CPUC decisions allow SCE to recover through the rates it is allowed to charge its customers reasonable procurement costs incurred in compliance with an approved procurement plan. Nonetheless, SCE's cash flows remain subject to volatility resulting from its procurement activities. In addition, SCE is subject to the risks of unfavorable or untimely CPUC decisions about the compliance of procurement activities with SCE's procurement plan and the reasonableness of certain procurement-related costs.

Many of SCE's power purchase contracts are tied to market prices for natural gas. Some of its contracts also are subject to volatility in market prices for electricity. SCE seeks to hedge

Table of Contents

its market price exposure to the extent authorized by the CPUC. SCE may not be able to hedge its risk for commodities on favorable terms or fully recover the costs of hedges through the rates it is allowed to charge its customers, which could adversely affect SCE's liquidity and results of operation.

In its power purchase contracts and other procurement arrangements, SCE is exposed to risks from changes in the credit quality of its counterparties, many of whom may be adversely affected by the conditions in the financial markets. If a counterparty were to default on its obligations, SCE could be exposed to potentially volatile spot markets for buying replacement power or selling excess power and this could have a material adverse effect on SCE's liquidity and financial condition if such costs cannot be recovered in a timely manner.

SCE is subject to extensive regulation and the risk of adverse regulatory decisions and changes in applicable regulations or legislation.

SCE operates in a highly regulated environment. SCE's business is subject to extensive federal, state and local energy, environmental and other laws and regulations. The CPUC regulates SCE's retail operations, and the FERC regulates SCE's wholesale operations. The Nuclear Regulatory Commission regulates SCE's nuclear power plants. The construction, planning, and project site identification of SCE's power plants and transmission lines in California are also subject to the jurisdiction of the California Energy Commission (for plants 50 MW or greater), and the CPUC. The construction, planning and project site identification of transmission lines that are outside of California are subject to the regulation of the relevant state agency.

SCE must periodically apply for licenses and permits from these various regulatory authorities and abide by their respective orders. Should SCE be unsuccessful in obtaining necessary licenses or permits or should these regulatory authorities initiate any investigations or enforcement actions or impose penalties or disallowances on SCE, SCE's business could be adversely affected. Existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to SCE or SCE's facilities in a manner that may have a detrimental effect on SCE's business or result in significant additional costs because of SCE's need to comply with those requirements.

Operating Risks

SCE's financial condition and results of operations could be materially adversely affected if it is unable to successfully manage the risks inherent in operating and improving its facilities.

SCE owns and operates extensive electricity facilities that are interconnected to the United States western electricity grid. SCE is also undertaking large-scale new infrastructure construction, which involves risks related to permitting, governmental approvals, and construction delays. The operation of SCE's facilities and the facilities of third parties on which it relies involves numerous risks, including:

- operating limitations that may be imposed by environmental or other regulatory requirements;

Table of Contents

- imposition of operational performance standards by agencies with regulatory oversight of SCE's facilities;
- environmental and personal injury liabilities caused by the operation of SCE's facilities;
- interruptions in fuel supply;
- blackouts;
- employee work force factors, including strikes, work stoppages or labor disputes;
- weather, storms, earthquakes, fires, floods or other natural disasters;
- acts of terrorism; and
- explosions, accidents, mechanical breakdowns and other events that affect demand, result in power outages, reduce generating output or cause damage to SCE's assets or operations or those of third parties on which it relies.

The occurrence of any of these events could result in lower revenues or increased expenses and liabilities, or both, which may not be fully recovered through insurance, rates or other means in a timely manner or at all.

There are inherent risks associated with operating nuclear power generating facilities.

Spent fuel storage capacity could be insufficient to permit long-term operation of SCE's nuclear plants.

SCE operates and is majority owner of San Onofre Nuclear Generating Station and is part owner of Palo Verde Nuclear Generating Station. The U.S. Department of Energy has defaulted on its obligation to begin accepting spent nuclear fuel from commercial nuclear industry participants by January 31, 1998. If SCE or the operator of Palo Verde were unable to arrange and maintain sufficient capacity for interim spent-fuel storage now or in the future, it could hinder the operation of the plants and impair the value of SCE's ownership interests until storage could be obtained, each of which may have a material adverse effect on SCE.

Existing insurance and ratemaking arrangements may not protect SCE fully against losses from a nuclear incident.

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection which is currently approximately $12.6 billion. SCE and other owners of the San Onofre and Palo Verde Nuclear Generating Stations have purchased the maximum private primary insurance available of $375 million per site. If this public liability limit 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. If this were to occur, tension could exist between the federal government's attempt to impose revenue-raising measures upon SCE and the CPUC's willingness to allow SCE to pass this liability along to its customers, resulting in under-collection of SCE's costs. There can be no assurance of SCE's ability to recover uninsured costs in the event federal appropriations are insufficient.

Table of Contents

SCE's insurance coverage may not be sufficient under all circumstances and SCE may not be able to obtain sufficient insurance.

SCE's insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which it may be subject. A loss for which SCE is not fully insured could materially and adversely affect SCE's financial condition and results of operations. Further, due to rising insurance costs and changes in the insurance markets, insurance coverage may not continue to be available at all or at rates or on terms similar to those presently available to SCE.

Financing Risks

SCE relies on access to the capital markets. If SCE were unable to access capital markets or the cost of capital was to substantially increase, its liquidity and operations could be adversely affected.

SCE's ability to fund operations and planned capital expenditure projects, as well as its ability to refinance debt and make scheduled payments of principal and interest depends on its cash flow and access to the capital markets. SCE's ability to arrange financing and the costs of such capital are dependent on numerous factors, including SCE's levels of indebtedness, maintenance of acceptable credit ratings, its financial performance, liquidity and cash flow, and other market conditions. Market conditions which could adversely affect SCE's financing costs and availability include:

- current state and liquidity of financial markets;
- market prices for electricity or gas;
- changes in interest rates and rates of inflation;
- terrorist attacks or the threat of terrorist attacks on SCE's facilities or unrelated energy companies; and
- the overall health of the utility industry.

SCE may not be successful in obtaining additional capital for these or other reasons. The failure to obtain additional capital from time to time may have a material adverse effect on SCE's liquidity and operations.

RISKS RELATING TO EMG

Environmental and Regulatory Risks

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

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

The controls imposed on the Midwest Generation plants as a result of the Combined Pollutant Standard may require material expenditures or unit shutdowns.

Midwest Generation has entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at the Midwest Generation plants. The agreement has been embodied in an Illinois rule called the Combined Pollutant Standard. All of Midwest Generation's Illinois coal-fired electric generating units are subject to the Combined Pollutant Standard. Capital expenditures relating to controls contemplated by the Combined Pollutant Standard could be significant and could make some units uneconomic to maintain or operate. Midwest Generation may ultimately decide to comply with Combined Pollutant Standard requirements by shutting down units rather than making improvements. Midwest Generation is evaluating technology and unit shutdown combinations and compliance solutions, to determine the economic effects of compliance with the Combined Pollutant Standard and optimal methods of compliance. For more information about the Combined Pollutant Standard requirements and Midwest Generation's plans for compliance, see "Item 1. Business Environmental Regulation of Edison International and Subsidiaries Air Quality Nitrogen Oxide and Sulfur Dioxide Clean Air Interstate Rule Illinois" and "Edison International Overview Environmental Developments Midwest Generation Environmental Compliance Plans and Costs" in the MD&A.

EME is subject to extensive energy industry regulation.

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

The FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, where it determines that potential market power might exist and that

Table of Contents

the public interest requires mitigation. In addition, many of EME's facilities are subject to rules, restrictions and terms of participation imposed and administered by various Regional Transmission Operators and Independent System Operators. For example, Independent System Operators and Regional Transmission Operators may impose bidding and scheduling rules, both to curb the potential exercise of market power and to facilitate market functions. Such actions may materially affect EME's results of operations.

Generation facilities are also subject to federal, state and local laws and regulations that govern, among other things, the geographical location, zoning, land use and operation of a project. EME in the course of its business must obtain and periodically renew licenses, permits and approvals for its facilities. There is no assurance that the introduction of new laws or other future regulatory developments will not have a material adverse effect on EME's business, results of operations or financial condition, nor is there any assurance that EME will be able to obtain and comply with all necessary licenses, permits and approvals for its projects. If projects cannot comply with all applicable regulations, EME's business, results of operations and financial condition could be adversely affected.

Market Risks

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

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

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

Table of Contents

the ability of regional pools to pay market participants' settlement prices for energy and related products;

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

legal and political challenges to the rules used to calculate capacity payments in the markets in which EME operates.

In addition, unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced when it is to be used. As a result, the wholesale power markets are subject to significant and unpredictable price fluctuations over relatively short periods of time. Due to the volume of sales into PJM from the fossil-fueled facilities, EME has concentrated exposure to market conditions and fluctuations in PJM. There is no assurance that EME's merchant energy power plants will be successful in selling power into their markets or that the prices received for their power will generate positive cash flows. If EME's merchant energy power plants do not meet these objectives, they may not be able to generate enough cash to service their own debt and lease obligations, which could have a material adverse effect on EME.

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

EME's business is subject to changes in fuel costs, which may negatively affect its financial results and financial position by increasing the cost of producing power. Fuel costs can be influenced by many factors outside EME's control, including weather, market liquidity, transportation inefficiencies, demand for energy commodities (both as fuel and as feedstock for manufacturing processes), natural gas, crude oil and coal production levels, natural disasters, wars, embargoes and other catastrophic events, governmental regulation and legislation, and the creditworthiness, liquidity and willingness of fuel suppliers and transporters to do business with EME and its subsidiaries. The fuel markets can be volatile, and actual fuel prices can differ from EME's expectations.

Although EME attempts to purchase fuel based on its expected requirements, it is still subject to the risks of supply interruptions, transportation cost increases, and fuel price volatility. In addition, fuel deliveries will not exactly match energy sales, due in part to the need to purchase fuel inventories in advance for reliability and dispatch requirements. The price at which EME can sell its energy may not rise or fall at the same rate as a corresponding rise or fall in fuel costs. All of these factors may have an adverse effect on EME's financial condition and results of operations.

EME may not hedge market risks effectively.

EME is exposed to market risks through its ownership and operation of merchant energy power plants and through its power marketing business. These market risks include, among others, volatility arising from the timing differences associated with buying fuel, converting fuel into energy and delivering energy to a buyer. EME uses forward contracts and derivative

Table of Contents

instruments, such as futures contracts and options, to manage market risks and exposure to fluctuating electricity and fuel prices. However, EME cannot provide assurance that these strategies will successfully mitigate market risks.

EME's hedging activities may not cover the entire exposure of its assets or positions to market price volatility, and the level of coverage will vary over time. Amounts hedged at any given time are not indicative of amounts that may be hedged in the future. Fluctuating commodity prices may affect EME's financial results, either favorably or unfavorably, to the extent that assets and positions have not been hedged. In addition, EME's risk management strategies may not be as effective as anticipated.

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

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

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

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

Competition could adversely affect EME's business.

EME has numerous competitors in all aspects of its business some of whom may have greater liquidity, greater access to credit and other financial resources, lower cost structures, larger staffs or more experience than EME. EME's competitors may be able to respond more quickly and efficiently to new laws and regulations or emerging technologies, or to devote greater resources to the development, operation, and maintenance of their power generation facilities than EME. Multiple participants in the wholesale markets, including many regulated utilities, have a lower cost of capital than most merchant generators and often are able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation assets without relying exclusively on market clearing prices to recover their investments. These factors could affect EME's ability to compete effectively in the markets in which those entities operate.

Newer plants owned by EME's competitors are often more efficient than EME's facilities and may also have lower costs of operation. Over time, some of EME's merchant facilities may become obsolete in their markets, or be unable to compete with such plants.

Table of Contents

In addition to the competition already existing in the markets in which EME presently operates or may consider operating in the future, EME is likely to encounter significant competition as a result of further consolidation of the power industry by mergers and asset reallocations, which could create larger competitors, as well as new market entrants.

Financing Risks

EME may not be able to raise capital on favorable terms, which could adversely affect its results of operation.

Liquidity is essential to EME's business. EME cannot provide assurance that its projected sources of capital will be available when needed or that its actual cash requirements will not be greater than expected. Lack of available capital may affect EME's ability to complete environmental improvements at the fossil-fueled facilities, which could lead to the eventual shutdown of a material part of such facilities. Lack of available capital could also affect EME's ability to complete the development of sites for renewable projects deploying current turbine commitments, which could lead to postponement or cancellation of the turbine commitments subject to the provisions of the related contracts. EME cannot provide assurance that its projected sources of capital will be available when needed or that its actual cash requirements will not be greater than expected.

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

As of December 31, 2009, EME's consolidated debt was approximately $4.0 billion. In addition, EME's subsidiaries had $3.2 billion of long-term, power plant lease obligations that are due over a period ranging up to 25 years. The substantial amount of consolidated debt and financial obligations presents the risk that EME and its subsidiaries might not have sufficient cash to service their indebtedness or long-term lease obligations and that the existing corporate debt, project debt and lease obligations could limit the ability of EME and its subsidiaries to grow their business, to compete effectively, to operate successfully under adverse economic conditions, to comply with evolving environmental regulations, or to plan for and react to business and industry changes. If cash flows and capital resources were insufficient to cover scheduled debt payments, EME or its subsidiaries might have to reduce or delay capital expenditures (including environmental improvements required by the CPS, which could in turn lead to unit shutdowns), sell assets, seek additional capital, or restructure or refinance the debt. The terms of EME's or its subsidiaries' debt may not allow these alternative measures, the debt or equity may not be available on acceptable terms, and these alternative measures may not satisfy all scheduled debt service obligations.

EME conducts a substantial portion of its operations through its subsidiaries and may be limited in its ability to access funds from these subsidiaries to service its debt.

EME depends to a large degree upon dividends and other intercompany transfers of funds from its subsidiaries to meet debt service and other obligations. In addition, the ability of EME's subsidiaries to pay dividends and make other payments to EME may be restricted by, among other things, applicable corporate and other laws, potentially adverse tax consequences, and agreements entered into by the subsidiaries. If EME is unable to access the cash flow of its subsidiaries, it may have difficulty meeting its own debt obligations.

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

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

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

Operating Risks

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

EME's development activities are subject to risks including, without limitation, risks related to the identification of project sites, financing, construction, permitting, governmental approvals and the negotiation of project agreements, including power purchase agreements. As a result of these risks, EME may not be successful in developing new projects, or the timing of such development may be delayed beyond the date that turbines are ready for installation. Projects under development may be adversely affected by delays in turbine deliveries or start-up problems related to turbine performance, and agreements with off-takers may contain damages and termination provisions related to failures to meet specified milestones. Moreover, recent economic conditions may affect the willingness of local utilities to enter into new power purchase agreements due to uncertainties over future load requirements, among other factors. If a project under development is abandoned, EME would expense all capitalized costs incurred in connection with that project, and could incur additional losses associated with any related contingent liabilities.

In support of its development activities, EME has entered into commitments to purchase wind turbines for future projects and may make substantial additional commitments in the future. If EME is not successful in developing new projects, it may be required to cancel turbine orders or sell turbines that were purchased. Such cancellations and/or sales may result in substantial losses and, under certain circumstances, may give rise to disputes with the turbine vendor. In

Table of Contents

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

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

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

- performance below expected levels of output, efficiency or availability;
- interruptions in fuel supply;
- disruptions in the transmission of electricity;
- curtailment of operations due to transmission constraints;
- breakdown or failure of equipment or processes;
- shortages of equipment or spare parts;
- imposition of new regulatory, permitting, or environmental requirements, or violations of existing requirements;
- restrictions on emissions;
- releases of hazardous substances to air, soil, surface water or groundwater;
- inability to transport and dispose of coal ash at reasonable prices;
- employee work force factors, including strikes, work stoppages or labor disputes;
- operator/contractor error; and
- catastrophic events such as terrorist activities, fires, tornadoes, earthquakes, explosions, floods or other similar occurrences affecting power generation facilities or the transmission and distribution infrastructure over which power is transported.

These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of or damage to the environment, and suspension of operations. The occurrence of one or more of the events listed above could decrease or eliminate revenues generated by EME's projects or significantly increase the costs of operating them, and could also result in EME being named as a defendant in lawsuits asserting claims for substantial damages, potentially including environmental cleanup costs, personal injury, property damage, fines and penalties.

Unplanned outages typically increase operation and maintenance expenditures and reduce revenues. EME could also be required to purchase replacement power in the open market to satisfy contractual commitments. Equipment and plant warranties, guarantees and insurance may not be sufficient or effective under all circumstances to cover lost revenues or increased expenses. A decrease or elimination in revenues generated by the facilities or an increase in the costs of operating them could decrease or eliminate funds available to meet EME's obligations as they become due and could have a material adverse effect on EME. A default

Table of Contents

under a financing obligation of a project entity could cause EME to lose its interest in the project.

The creditworthiness of EME's customers, suppliers, transporters and other business partners could affect EME's business and operations.

EME is exposed to risks associated with the creditworthiness of its key customers, suppliers and business partners, many of whom may be adversely affected by the current conditions in the financial markets. Deterioration in the financial condition of EME's counterparties increases the possibility that EME may incur losses from the failure of counterparties to perform according to the terms of their contractual arrangements.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As a holding company, Edison International does not directly own any significant properties other than the stock of its subsidiaries. The principal properties of SCE are described above under "Southern California Edison Company Properties of SCE." Properties of EME are discussed above under "Edison Mission Group Inc. Properties of EME".

ITEM 3. LEGAL PROCEEDINGS

Catalina South Coast Air Quality Management District Potential Environmental Proceeding

During the period 2006-2008, the South Coast Air Quality Management District ("SCAQMD") issued five notices of violation ("NOVs") alleging violations of the NO_x emission limits and related Regional Clean Air Incentives Market (RECLAIM) trading credit (to offset NO_x emissions) requirements by certain of SCE's diesel generation units on Catalina Island. A settlement agreement, which resolves all of the NOVs, was fully executed in April 2009 and requires SCE to install new equipment by December 31, 2011 or pay a $3 million fine if the equipment is not installed by that date.

Table of Contents

Homer City New Source Review Notice of Violation

On June 12, 2008, Homer City received an NOV from the US EPA alleging that, beginning in 1988, 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 ("PSD") requirements of the Clean Air Act ("CAA"). The US EPA also alleges that Homer City has failed to file timely and complete Title V permits. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. On June 30, 2009 and January 2, 2010, the US EPA issued requests for information to Homer City under Section 114 of the CAA. Homer City is working on a response to the requests. 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 cannot predict at this time what effect this matter may have on its facilities, its results of operations, financial position or cash flows.

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 Homer City acquired the Homer City facilities. The sellers responded by denying the indemnity obligation, but accepting the defense of the claims.

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 Homer City for costs and liabilities associated with the Homer City NOV. Homer City responded by undertaking the indemnity obligation and defense of the claims.

Midwest Generation New Source Review Lawsuit

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 PSD requirements and of the New Source Performance Standards of the CAA, including alleged requirements to obtain a construction permit and to install BACT at the time of the projects. The US EPA also alleged that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the CAA. Finally, the US EPA alleged violations of certain opacity and particulate matter standards at the Midwest Generation plants. At approximately the same time, Commonwealth Edison received an NOV substantially similar to the Midwest Generation NOV. Midwest Generation, Commonwealth Edison, the US EPA, and the U.S. Department of Justice ("DOJ"), along with several Chicago-based environmental action groups, had discussions designed to explore the possibility of a settlement but no settlement resulted.

On August 27, 2009, the US EPA and the State of Illinois filed a complaint in the Northern District of Illinois against Midwest Generation, but not Commonwealth Edison, alleging claims substantially similar to those in the NOV. In addition to seeking penalties ranging from $25,000 to $37,500 per violation, per day, the complaint calls for an injunction ordering Midwest Generation to install best available control technology ("BACT") at all units subject to the complaint; to obtain new PSD or NSR permits for those units; to amend its applications under Title V of the CAA; to conduct audits of its operations to determine whether any additional modifications have occurred; and to offset and mitigate the harm to public health and the environment caused by the alleged CAA violations. The remedies sought by the plaintiffs in the lawsuit could go well beyond those required under the CPS. By order dated January 19, 2010, the court allowed a group of Chicago-based environmental action groups to intervene in the case.

The owner participants of the Powerton and Joliet Stations have sought indemnification and defense from Midwest Generation and/or EME for costs and liabilities associated with these matters. EME responded by undertaking the indemnity obligation and defense of the claims. An adverse decision could involve penalties and remedial actions that would have a material adverse impact on the financial condition and results of operations EME.

EME cannot predict the outcome of these matters or estimate the impact on its facilities, its results of operations, financial position or cash flows.

Navajo Nation Litigation

Information about the Navajo Nation litigation appears in the "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

Table of Contents

Pursuant to Form 10-K's General Instruction G(3), the following information is included as an additional item in Part I:

EXECUTIVE OFFICERS OF THE REGISTRANT

Executive Officer[1]	Age at December 31, 2009	Company Position
Theodore F. Craver, Jr.	58	Chairman of the Board, President and Chief Executive Officer, Edison International
Robert L. Adler	62	Executive Vice President and General Counsel, Edison International
Polly L. Gault	56	Executive Vice President, Public Affairs, Edison International
W. James Scilacci	54	Executive Vice President, Chief Financial Officer and Treasurer, Edison International
Daryl D. David	55	Senior Vice President, Human Resources, Edison International
Barbara J. Parsky	62	Senior Vice President, Corporate Communications, Edison International
Mark C. Clarke	53	Vice President and Controller, Edison International
Alan J. Fohrer	59	Chairman of the Board and Chief Executive Officer, SCE
John R. Fielder	64	President, SCE
Ronald L. Litzinger	50	Chairman of the Board, President and Chief Executive Officer, EMG and EME

1 The term "Executive Officers" is defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act. Pursuant to this rule, the Executive Officers of Edison International include certain elected officers of Edison International and its subsidiaries, all of whom may be deemed significant policy makers of Edison International. None of the Edison International Executive Officers are related to any other by blood or marriage.

As set forth in Article IV of Edison International's and the relevant subsidiary's Bylaws, the elected officers of Edison International and its subsidiaries are chosen annually by, and serve at the pleasure of, Edison International and the relevant subsidiary's Board of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. All of the officers of Edison International and its subsidiaries have been actively engaged in the business of Edison International and its subsidiaries for more than five years, except for Messrs. Adler and David, and have served in their present positions for the periods stated below. Additionally,

Table of Contents

those officers who have had other or additional principal positions in the past five years had the following business experience during that period:

Executive Officers	Company Position	Effective Dates
Theodore F. Craver, Jr.	Chairman of the Board, President and Chief Executive Officer, Edison International	August 2008 to present
	President, Edison International	April 2008 to July 2008
	Chairman of the Board, President and Chief Executive Officer, EMG	November 2005 to March 2008
	Chairman of the Board, President and Chief Executive Officer, EME	January 2005 to March 2008
Robert L. Adler	Executive Vice President and General Counsel, Edison International	August 2008 to present
	Executive Vice President, Edison International	July 2008 to August 2008
	Partner, Munger, Tolles & Olson LLP[1]	January 1978 to June 2008
Polly L. Gault	Executive Vice President, Public Affairs, Edison International	March 2007 to present
	Executive Vice President, Public Affairs, SCE	March 2007 to September 2008
	Senior Vice President, Public Affairs, Edison International and SCE	March 2006 to February 2007
	Vice President, Public Affairs, Edison International and SCE	January 2004 to February 2006
W. James Scilacci	Executive Vice President, Chief Financial Officer and Treasurer, Edison International	August 2008 to present
	Senior Vice President and Chief Financial Officer, EME	March 2005 to July 2008
	Senior Vice President and Chief Financial Officer, EMG	November 2005 to July 2008
	Senior Vice President and Chief Financial Officer, SCE	January 2003 to March 2005
Daryl D. David	Senior Vice President, Human Resources, Edison International	June 2009 to present
	Executive Vice President & Chief Human Resources Officer, Washington Mutual, Inc.[2]	May 2000 to October 2008
Barbara J. Parsky	Senior Vice President, Corporate Communications, Edison International	March 2007 to present
	Senior Vice President, Corporate Communications, SCE	March 2007 to September 2008
	Vice President, Corporate Communications, Edison International and SCE	January 2003 to February 2007

Table of Contents

Executive Officers	Company Position	Effective Dates
Mark C. Clarke	Vice President and Controller, Edison International	August 2009 to present
	Vice President and Controller, EME	January 2003 to July 2009
	Controller, EME	May 2002 to December 2002
Alan J. Fohrer	Chairman of the Board and Chief Executive Officer, SCE	June 2007 to present
	Chief Executive Officer, SCE	January 2002 to June 2007
John R. Fielder	President, SCE	October 2005 to present
	Senior Vice President, Regulatory Policy and Affairs, SCE	February 1998 to October 2005
Ronald L. Litzinger	Chairman of the Board, President and Chief Executive Officer, EMG and EME	April 2008 to present
	Senior Vice President, Transmission and Distribution, SCE	May 2005 to March 2008
	Vice President, Strategic Planning, Edison International	May 2004 to April 2005

1 Munger, Tolles & Olson LLP is a California-based law firm and is not a parent, subsidiary or affiliate of Edison International. Mr. Adler also served as a Co-Managing Partner.

2 Washington Mutual was a bank holding company and the former owner of Washington Mutual Bank and is not a parent, subsidiary or affiliate of Edison International.

Table of Contents

PART II

ITEM 4. RESERVED

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

Edison International Common Stock is traded on the New York Stock Exchange under the symbol "EIX."

Market information responding to Item 5 is included in "Item 8. Edison International Notes to Consolidated Financial Statements Note 19. Quarterly Financial Data." There are restrictions on the ability of Edison International's subsidiaries to transfer funds to Edison International that materially limit the ability of Edison International to pay cash dividends. Such restrictions are discussed in the MD&A under the heading "Edison International Overview Parent Company Liquidity and in "Item 8. Edison International Notes to Consolidated Financial Statements Note 3. Liabilities and Lines of Credit." The number of common stock shareholders of record of Edison International was 47,620 on February 25, 2010. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page hereof.

Issuer Purchase of Equity Securities

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

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2009 to October 31, 2009	876,310	$ 33.11		
November 1, 2009 to November 30, 2009	286,610	$ 32.20		
December 1, 2009 to December 31, 2009	1,135,301	$ 35.44		
Total	2,298,221	$ 34.15		

1 The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's: (i) 401(k) Savings Plan; (ii) Dividend Reinvestment and Direct Stock Purchase Plan; and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were

Table of Contents

never registered in Edison International's' name and none of the shares pur chased were retired as a result of the transactions.

Comparison of Five-Year Cumulative Total Return

	12/04	12/05	12/06	12/07	12/08	12/09
Edison International	100	140	149	179	111	125
S & P 500 Index	100	105	121	128	81	102
Philadelphia Utility Index	100	118	142	169	123	135

Note: Assumes $100 invested on December 31, 2004 in stock or index including reinvestment of dividends. Performance of the Philadelphia Utility Index is regularly reviewed by management and the Board of Directors in understanding Edison International's relative performance and is used in conjunction with elements of the company's incentive compensation program.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

Selected Financial Data: 2005 - 2009

(in millions, except per-share amounts)	2009	2008	2007	2006	2005
Edison International and Subsidiaries					
Operating revenue	$ 12,361	$ 14,112	$ 12,868	$ 12,169	$ 11,417
Operating expenses	$ 10,963	$ 11,549	$ 10,359	$ 9,680	$ 9,102
Income from continuing operations	$ 952	$ 1,348	$ 1,307	$ 1,273	$ 1,299
Net income	$ 945	$ 1,348	$ 1,305	$ 1,371	$ 1,328
Net income attributable to common shareholders	$ 849	$ 1,215	$ 1,098	$ 1,181	$ 1,137
Weighted-average shares of common stock outstanding (in millions)	326	326	326	326	326
Basic earnings (loss) per share:					
Continuing operations	$ 2.61	$ 3.69	$ 3.34	$ 3.28	$ 3.38
Discontinued operations	$ (0.02)	$	$ (0.01)	$ 0.30	$ 0.09
Total	$ 2.59	$ 3.69	$ 3.33	$ 3.58	$ 3.47
Diluted earnings per share	$ 2.58	$ 3.68	$ 3.31	$ 3.57	$ 3.45
Dividends declared per share	$ 1.245	$ 1.225	$ 1.175	$ 1.10	$ 1.02
Book value per share at year-end	$ 30.21	$ 29.21	$ 25.92	$ 23.66	$ 20.30
Market value per share at year-end	$ 34.78	$ 32.12	$ 53.37	$ 45.48	$ 43.61
Rate of return on common equity	8.7%	13.7%	13.6%	16.5%	18.1%
Price/earnings ratio	13.4	8.7	16.0	12.7	12.6
Ratio of earnings to fixed charges	1.71	2.72	2.40	2.46	2.42
Total assets	$ 41,444	$ 44,615	$ 37,523	$ 36,261	$ 34,791
Long-term debt	$ 10,437	$ 10,950	$ 9,016	$ 9,101	$ 8,833
Preferred and preference stock of utility not subject to mandatory redemption	$ 907	$ 907	$ 915	$ 915	$ 729
Common shareholders' equity	$ 9,841	$ 9,517	$ 8,444	$ 7,709	$ 6,615
Retained earnings	$ 7,500	$ 7,078	$ 6,311	$ 5,551	$ 4,798
Southern California Edison Company					
Operating revenue	$ 9,965	$ 11,248	$ 10,233	$ 9,859	$ 9,065
Net income available for common stock	$ 1,226	$ 683	$ 707	$ 776	$ 725
Basic earnings per Edison International common share	$ 3.76	$ 2.10	$ 2.17	$ 2.38	$ 2.22
Total assets	$ 32,474	$ 32,568	$ 27,477	$ 26,110	$ 24,703
Rate of return on common equity	17.3%	10.7%	12.0%	15.0%	15.3%
Edison Mission Energy					
Revenue	$ 2,377	$ 2,811	$ 2,580	$ 2,239	$ 2,265
Income from continuing operations	$ 201	$ 500	$ 415	$ 316	$ 414
Net income attributable to common shareholders	$ 197	$ 501	$ 414	$ 414	$ 442
Total assets	$ 8,633	$ 9,080	$ 7,272	$ 7,235	$ 6,655
Rate of return on common equity	7.2%	21.7%	18.4%	18.4%	24.2%
Edison Capital					
Revenue	$ 25	$ 58	$ 56	$ 73	$ 77
Net income attributable to common shareholders	$ (589)	$ 58	$ 69	$ 89	$ 81
Total assets	$ 836	$ 3,033	$ 2,977	$ 3,199	$ 3,376
Rate of return on common equity	[1]	14.2%	15.6%	9.6%	12.3%

[1] In 2009 Edison Capital had negative common equity resulting from the Global Settlement and termination of its interests in cross-border leases. (See "Global Settlement" in Note 4 for further discussion.)

The selected financial data was derived from Edison International's audited financial statements and is qualified in its entirety by the more detailed information and financial statements, including notes to these financial statements, included in this annual report.

Table of Contents

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

EDISON INTERNATIONAL OVERVIEW

Introduction

Edison International is a holding company whose principal operating subsidiaries are SCE, a rate-regulated electric utility, and EMG, the holding company of Edison International's competitive power generation (EME) and financial services (Edison Capital) segments. As a holding company, Edison International's progress and outlook are the result of developments at its operating subsidiaries.

This overview is presented in five sections:

- Highlights of operating results;
- SCE capital investment plan to maintain reliability and expand the capability of SCE's distribution and transmission infrastructure, support initiatives in California to increase renewable energy, construct and replace generating assets and deploy advanced metering capability;
- Environmental developments, including compliance activities at EMG's Midwest Generation and Homer City plants, and legislative, regulatory and legal developments related to greenhouse gases and once-through cooling;
- Update on EMG's renewable programs; and
- Information regarding Edison International liquidity.

Table of Contents

Highlights of Operating Results

(in millions)	2009	2008	Change	2007
Net Income attributable to Edison International				
SCE	$ 1,226	$ 683	$ 543	$ 707
EMG	(395)	561	(956)	410
EIX Parent and Other	18	(29)	47	(19)
EIX Consolidated	849	1,215	(366)	1,098
Non-Core Items				
SCE Regulatory Items	46	(49)	95	31
Global Settlement[1]				
SCE	306		306	
EMG[1]	(610)		(610)	
EIX Parent and Other	50		50	
EMG Debt Extinguishment				(148)
EMG Discontinued Operations	(7)		(7)	(2)
Total non-core items	(215)	(49)	(166)	(119)
Core Earnings				
SCE	874	732	142	676
EMG	222	561	(339)	560
EIX Parent and Other	(32)	(29)	(3)	(19)
EIX Consolidated	$ 1,064	$ 1,264	$ (200)	$ 1,217

[1] Includes termination of Edison Capital's cross border leases.

Edison International's earnings are prepared in accordance with generally accepted accounting principles used in the United States. Management uses core earnings by principal operating subsidiary internally for financial planning and for analysis of performance. Core earnings by principal operating subsidiary are also used when communicating with analysts and investors regarding our earnings results to facilitate comparisons of the Company's performance from period to period. Core earnings is a non-GAAP financial measure and may not be comparable to those of other companies. Core earnings are defined as earnings attributable to Edison International shareholders less income or loss from discontinued operations and income or loss from significant discrete items that management does not consider representative of ongoing earnings, such as: settlement of prior year tax liabilities; exit activities, including lease terminations, asset impairments, sale of certain assets, early debt extinguishment costs and other activities that are no longer continuing; and non-recurring regulatory or legal proceedings.

SCE's 2009 core earnings increased from 2008 primarily due to higher operating income associated with the CPUC and FERC 2009 general rate case decisions, partially offset by higher income taxes. In addition, core earnings were favorably impacted from lower than planned financings during the year, primarily from cash received for tax-related timing differences and other benefits.

Table of Contents

During 2009, SCE received general rate case decisions from the CPUC and FERC, as follows:

- The CPUC issued a decision in SCE's 2009 GRC, authorizing a $4.83 billion revenue requirement for 2009, an increase of $512 million from SCE's 2008 revenue requirement, effective January 1, 2009. The CPUC also authorized a methodology that would result in an approximate revenue requirement of $5.04 billion in 2010 and $5.25 billion in 2011.

- The FERC approved a settlement to the 2009 rate case effective March 1, 2009. The settlement provides for a transmission revenue requirement of $448 million, an increase of $136 million over the previously authorized amount.

EMG 2009 core earnings were significantly lower than 2008 primarily due to the following:

- Lower wholesale energy prices reduced revenues from EME's merchant coal-fired generation and trading operations. The effects of the economic recession and mild weather during the summer months contributed to declines in electrical demand for the Northern Illinois and PJM West locations during 2009. Electrical load, calculated from data published by PJM, for these locations declined 5% and 3%, respectively, during 2009 compared to 2008. In addition, the price of natural gas, which often serves as the marginal fuel source in the region, declined significantly. The reduction in natural gas prices together with lower electrical demand resulted in significantly lower wholesale energy prices. The average 24-hour PJM real-time price for energy at the Northern Illinois Hub and the PJM West Hub declined to $28.86/MWh and $38.31/MWh, respectively, during 2009 as compared to $49.01/MWh and $68.56/MWh, respectively, during 2008.

- Lower electrical load contributed to decreased transmission congestion in the eastern power grid, thereby resulting in $115 million lower trading income in 2009 as compared to 2008.

- Higher costs were incurred at Midwest Generation to comply with the CAIR annual NO_x emission program that began in 2009 and new mercury emission controls. Partially offsetting these higher costs were cost reductions at Midwest Generation and Homer City due in part to the deferral of plant overhaul activities.

- Lower earnings occurred at Edison Capital primarily due to a decline in lease income following the termination of cross border leases, which occurred as part of the Global Settlement with the Internal Revenue Service.

Consolidated changes in non-core items for Edison International include the following:

- An after-tax loss of $254 million in 2009 resulted from the Global Settlement with the Internal Revenue Service and termination of Edison Capital's cross border leases. The 2009 loss is net of a $19 million tax benefit recorded in the fourth quarter from a revised estimate of federal interest related to the settlement. The Global Settlement resolved federal tax disputes related to Edison Capital's cross-border, leveraged leases through 2009, and all other outstanding federal tax disputes and affirmative claims of Edison International for tax years 1986 through 2002.

- An after-tax non-cash benefit of $46 million was recorded in 2009 from the transfer of the Mountainview power plant to utility rate base pursuant to approvals by the CPUC and FERC.

Table of Contents

- An after-tax charge of $49 million in 2008 from a decision by the CPUC disallowing certain amounts and imposing penalties under its performance-based ratemaking program for the period 1997 2003.

See "SCE: Results of Operations" for discussion of SCE results of operations, including a comparison of 2008 results to 2007. Also, see "EMG: Results of Operations" for discussion of EMG results of operations, including a comparison of 2008 results to 2007.

SCE Capital Program

SCE's capital program is focused primarily in five areas:

- Upgrading and constructing new transmission lines to expand capacity to utilize renewable energy, including the Tehachapi, Devers-Colorado River and Eldorado-Ivanpah projects;

- Maintaining reliability and expanding capability of SCE's transmission and distribution system;

- Developing and installing up to 250 MW of utility-owned solar photovoltaic generating facilities (generally ranging in size from 1 to 2 MW each) on commercial and industrial rooftops and other space in SCE's service territory;

- Replacing steam generators at San Onofre intended to enable operations until at least the end of its initial license period in 2022; and

- Installing "smart" meters in approximately 5.3 million households and small businesses referred to as Edison SmartConnect .

SCE plans to utilize much of the cash currently generated from its operations and issuance of additional debt and preferred stock for its capital program. SCE's capital expenditures in 2009 totaled $2.9 billion. SCE projects that capital expenditures will be in the range of $3.3 billion to $4.0 billion in 2010 and that the 2010 - 2014 total capital investment plan will be in the range of $18 billion to $21.5 billion. The rate of actual capital spending will be affected by permitting, regulatory, market and other factors as discussed further under "SCE: Liquidity and Capital Resources Capital Investment Plan."

Environmental Developments

Midwest Generation Environmental Compliance Plans and Costs

Midwest Generation is subject to various requirements with respect to environmental compliance for the Midwest Generation plants. In 2006, Midwest Generation entered into an agreement with the Illinois EPA, which has been embodied in an Illinois rule called the CPS, to control emission of mercury, NO_x and SO_2 from its coal-fired plants. During 2008 and 2009, Midwest Generation installed equipment to reduce its mercury emissions. During 2009, Midwest Generation also conducted tests of NO_x removal technology based on SNCR and SO_2 removal using flue gas desulfurization technology based on dry sodium sorbent injection that may be employed to meet CPS requirements. Based on this testing, Midwest Generation has concluded that installation of SNCR technology on multiple units will meet the NO_x

portion of the CPS. Capital expenditures for installation of SNCR technology are expected to be approximately $88 million in 2010 and $70 million in 2011.

Testing of flue gas desulfurization technology based on injection of dry sodium sorbent demonstrated significant reductions in SO_2 emissions when using low-sulfur coal employed by Midwest Generation; however, further analysis and evaluation are required to determine the appropriate method to comply with the SO_2 portion of the CPS. Use of flue gas desulfurization technology based on injection of dry sodium sorbent in combination with Midwest Generation's use of low-sulfur coal is expected to require substantially less capital and installation time than dry scrubber technology, but would likely result in higher ongoing operating costs and may consequently result in lower dispatch rates and competitiveness of the plants. Midwest Generation may also combine the use of dry sorbent injection technology with upgrades to its particulate removal systems to meet environmental regulations.

Midwest Generation does not yet know what specific method of SO_2 removal will be used or the total costs that will be incurred to comply with the CPS. Any and a decision regarding whether or not to proceed with the above or other approaches to compliance remains subject to further analysis and evaluation of several factors, including market conditions, regulatory and legislative developments and forecasted capital and operating costs. Due to existing uncertainties about these factors, Midwest Generation may defer final decisions about particular units for the maximum time available. Accordingly, final decisions on whether to install controls, the particular controls that will be installed, and the resulting capital commitments may not occur for up to two years for some of the units and potentially further out for others. Midwest Generation could elect to shut down units when required in order to comply with the SO_2 removal requirements of the CPS. Midwest Generation continues to evaluate various scenarios and cannot predict the extent of shutdowns and retrofits or the particular combination of retrofits and shutdowns it may ultimately employ to comply with CPS.

Midwest Generation New Source Review Lawsuit

In August 2009, the US EPA and the State of Illinois filed a lawsuit against Midwest Generation in Illinois federal court based on claims contained in a 2007 NOV regarding alleged violations of the New Source Performance Standards of the CAA, the CAA's Title V operating permit requirements and applicable opacity and particulate matter standards. Midwest Generation is contesting such claims. The lawsuit seeks, among other things, substantial monetary penalties and an injunction requiring Midwest Generation to install controls sufficient to meet BACT emissions rates as determined by the court at all units subject to the lawsuit. See "Item 3. Legal Proceedings Midwest Generation New Source Review Lawsuit" for further discussion. Should liability of Midwest Generation be established, remedies ordered by the court could go beyond what is required for compliance with the CPS.

Homer City Environmental Issues and Capital Resource Limitations

Homer City operates SCR equipment on all three units to reduce NO_x emissions, operates flue gas desulfurization equipment on Unit 3 to reduce SO_2 emissions, and uses coal-cleaning equipment onsite to reduce the ash and sulfur content of raw coal to meet both combustion and environmental requirements. Homer City may be required to install additional

Table of Contents

environmental equipment on Unit 1 and Unit 2 to comply with environmental regulations under the CAIR and Pennsylvania mercury regulations. If required, the timing of such compliance remains uncertain. Homer City projects that if flue gas desulfurization equipment becomes required, it would need to make capital commitments for such equipment three to four years in advance of the effectiveness of such requirements. Homer City continues to review technologies available to reduce SO_2 and mercury emissions and to monitor developments related to mercury and other environmental regulations. Restrictions under the agreements entered into as part of Homer City's 2001 sale-leaseback transaction could affect, and in some cases significantly limit or prohibit, Homer City's ability to incur indebtedness or make capital expenditures. Homer City will have limited ability to obtain additional outside capital for such projects without amending its lease and related agreements. EME is under no contractual or other obligation to provide funding to Homer City.

Greenhouse Gas Regulation Developments

The nature of future environmental regulation and legislation will have a substantial impact on Edison International. Edison International believes that resolution of current uncertainties about the future, through well-balanced and appropriately flexible regulation and legislation, is needed to support the necessary evolution of the electric industry into using cleaner, more efficient infrastructure and to attract the capital ultimately needed for this effort. Legislative, regulatory, and legal developments related to potential controls over greenhouse gas emissions in the United States are ongoing. Actions to limit or reduce greenhouse gas emissions could significantly increase the cost of generating electricity from fossil fuels as well as the cost of purchased power. In the case of utilities, like SCE, these costs are generally borne by customers, whereas the increased costs for competitive generators, like EME, must be recovered through market prices for electricity.

Recent significant developments include the following:

- Legislation to regulate greenhouse gas emissions continues to be considered by Congress; however, the timing, content, and potential effects on Edison International and its subsidiaries of any greenhouse gas legislation that may be enacted remain uncertain.

- In December 2009, the US EPA issued a final finding that certain greenhouse gases, including carbon dioxide, threaten the public health and welfare. The US EPA has issued a proposed rule, known as the "greenhouse gas tailoring rule," under which all new and major modifications of existing stationary sources emitting 25,000 metric tons of carbon dioxide equivalents annually, including power plants, would be required to include BACT to minimize their greenhouse gas emissions. Since the current proposal affects only new or modified sources, it is not expected to have any immediate effect, if adopted, on existing fossil-fuel generating stations of SCE, Midwest Generation or Homer City, but it could affect the cost of new construction or modifications. US EPA could also use its authority in the future to regulate existing sources of greenhouse gas emissions. If controls are required to be installed at the facilities of Edison International subsidiaries in the future in order to reduce greenhouse gas emissions pursuant to regulations issued by the US EPA or others, the potential impact will depend on the nature of the controls applied, which remains uncertain.

Table of Contents

Three recent court cases addressed the question of whether power plants that emit greenhouse gases constituted public nuisances that could be held liable for damages or other remedies. In one case (in which Edison International is a named defendant): a California federal district court dismissed the plaintiffs' claims. In the other two, federal courts of appeals permitted the suits to go forward. Each of these differing results remains subject to appeal and thus the ultimate impact of these cases remains uncertain. Edison International cannot predict whether these recent decisions will result in the filing of new actions with similar claims or whether Congress, in considering climate legislation, will address directly the availability of courts for these sorts of claims.

Governor Schwarzenegger issued an executive order to increase California's renewable energy goals from 20% to 33% and has directed the CARB to adopt a regulation consistent with 33% of retail sellers annual electricity sales being obtained from renewable energy sources by 2020. Achieving a 33% renewables portfolio standard in this timeframe is highly ambitious, given the magnitude of the infrastructure build-out required and the slow pace of transmission permitting and approvals. The CARB is also considering a number of direct regulations to reduce greenhouse gases in California, which requirements could go beyond those ultimately imposed by Congress or the US EPA.

Once-Through Cooling

Last year, the California State Water Resources Board released a draft policy, which would establish closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like San Onofre and many of the existing gas-fired power plants along the California coast. If the policy is adopted by the Board, it may result in significant capital expenditures at San Onofre and may affect its operations. It may also significantly impact SCE's ability to procure generating capacity from fossil-fuel plants that use ocean water in once-through cooling systems. It may also impact system reliability and the cost of electricity to the extent other coastal power plants in California are forced to shut down or limit operations. The policy has the potential to adversely affect California's nineteen once-through cooled power plants, which provide over 21,000 MW of combined, in-state generation capacity, including over 9,100 MW of capacity interconnected within SCE's service territory.

EME Renewable Program

EME has a development pipeline of potential wind projects with projected installed capacity of approximately 4,000 MW at January 31, 2010 compared to approximately 5,000 MW at December 31, 2008. The decline in the pipeline is primarily due to the transfer of projects into construction and cost containment efforts resulting in the reduction in the number of projects funded under our joint development agreements. EME had purchase contracts for 512 MW of wind turbines for future projects as of December 31, 2009. EME plans to deploy these wind turbines when projects meet acceptable financial thresholds, have long-term power sales agreements, and can attract long-term project financing. If EME is unable to develop such projects on acceptable terms and conditions, certain turbine orders may be terminated. Such an event would likely result in a material charge.

At December 31, 2009, EME had two projects under construction: the 240 MW Big Sky wind project, and the 150 MW Cedro Hill wind project, which are scheduled for completion in early 2011 and late 2010, respectively. EME has obtained financing for the Big Sky wind project ($206 million). During the first quarter of 2010, EME commenced construction of the 130 MW Taloga wind project located in Oklahoma and executed a power sales agreement for an 80 MW project located in Nebraska, referred to as the Laredo Ridge wind project. After designating turbines for these projects, EME has reduced its available turbines for future projects to 302 MW.

The pace of further growth in EME's renewables program will be subject to availability of projects that meet EME's requirements and the capital needed for development, and it may be affected by future decisions about capital expenditures for environmental compliance by its coal fleet.

Parent Company Liquidity

The parent company's liquidity and its ability to pay operating expenses and dividends to common shareholders have historically been dependent on dividends from SCE, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to bank and capital markets. During 2009, Edison International paid common dividends of $404 million to its shareholders. Given its subsidiaries' plans to use their current cash flow for their respective capital needs, Edison International (parent) expects to incur additional borrowings to fund its own activities.

At December 31, 2009, Edison International (parent) had approximately $18 million of cash and equivalents on hand. The following table summarizes the status of the Edison International (parent) credit facility at December 31, 2009:

(in millions)	**Edison International (parent)**
Commitment	$ 1,426
Outstanding borrowings	(85)
Outstanding letters of credit	
Amount available	$ 1,341

Edison International has a debt covenant in its credit facility that requires a consolidated debt to total capitalization ratio of less than or equal to 0.65 to 1 to be met. At December 31, 2009, Edison International's consolidated debt to total capitalization ratio was 0.53 to 1.

Table of Contents

SOUTHERN CALIFORNIA EDISON COMPANY

RESULTS OF OPERATIONS

SCE's results of operations are derived mainly through two sources:

- Utility earning activities, which mainly represent CPUC and FERC-authorized base rates, which allow a reasonable return, and CPUC-authorized incentive mechanisms; and
- Utility cost-recovery activities, which mainly represent CPUC-authorized balancing accounts, which allow recovery of costs incurred or provide mechanisms to track and recover or refund differences in forecasted and actual amounts. Balancing accounts do not allow for a return.

Utility earning activities include base rates that are designed to recover forecasted operation and maintenance costs, certain capital-related carrying costs, interest, taxes and a return, including the return on capital projects recovered through balancing account mechanisms. Differences between authorized and actual results impact earnings. Also, included in utility earning activities are revenues or penalties related to incentive mechanisms, other operating revenue, and regulatory charges or disallowances, if any.

Utility cost-recovery activities include rates which provide for recovery, subject to reasonableness review, of fuel costs, purchased power costs, public purpose related-program costs (including energy efficiency and demand-side management programs), nuclear decommissioning expense, certain operation and maintenance expenses, and depreciation expense related to certain projects. There is no return for cost-recovery expenses.

Table of Contents

Electric Utility Results of Operations

The following table is a summary of SCE's results of operations for the periods indicated. The presentation below separately identifies utility earning activities and utility cost-recovery activities (including Big 4).

	2009			2008			2007		
(in millions)	**Utility Earning Activities**	**Utility Cost-Recovery Activities**[1]	**Total Consolidated**	**Utility Earning Activities**	**Utility Cost-Recovery Activities**[1]	**Total Consolidated**	**Utility Earning Activities**	**Utility Cost-Recovery Activities**[1]	**Total Consolidated**
Operating revenue	$ 5,242	$ 4,723	$ 9,965	$ 4,728	$ 6,520	$ 11,248	$ 4,439	$ 5,794	$ 10,233
Fuel and purchased power		3,472	3,472		5,245	5,245		4,426	4,426
Operations and maintenance	2,091	1,063	3,154	2,031	982	3,013	1,877	961	2,838
Depreciation, decommissioning and amortization	1,113	65	1,178	1,033	81	1,114	938	73	1,011
Property taxes and other	240	4	244	225	7	232	209	8	217
Gain on sale of assets		(1)	(1)		(9)	(9)			
Total operating expenses	3,444	4,603	8,047	3,289	6,306	9,595	3,024	5,468	8,492
Operating income	1,798	120	1,918	1,439	214	1,653	1,415	326	1,741
Net interest expense and other	(297)	(1)	(298)	(415)	8	(407)	(359)	18	(341)
Income before income taxes	1,501	119	1,620	1,024	222	1,246	1,056	344	1,400
Income tax expense	224	25	249	290	52	342	298	39	337
Net income	1,277	94	1,371	734	170	904	758	305	1,063
Net income attributable to noncontrolling interest		94	94		170	170		305	305
Dividends on preferred and preference stock not subject to mandatory redemption	51		51	51		51	51		51
Net income available for common stock	$ 1,226	$	$ 1,226	$ 683	$	$ 683	$ 707	$	$ 707
Core Earnings[2]			$ 874			$ 732			$ 676
Non-Core Earnings:									
Regulatory items			46			(49)			31

Global tax settlement	306		
Total SCE GAAP Earnings	$ 1,226	$ 683	$ 707

1 SCE has contracts with certain QFs that contain variable contract provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by EME. The QFs sell electricity to SCE and steam to nonrelated parties. In accordance with authoritative accounting guidance which requires consolidation of certain variable interest entities, SCE consolidates these Big 4 projects. SCE does not derive any income or cash flows from these entities.

2 See use of Non-GAAP financial measure in "Edison International Overview Highlights of Operating Results."

Table of Contents

Utility Earning Activities

2009 vs. 2008

Utility earning activities were primarily affected by:

Higher operating revenue of $514 million primarily due to the following:

$485 million increase resulting from the implementation of SCE's 2009 CPUC GRC decision, which authorized an increase of $512 million ($27 million of which is reflected in utility cost-recovery activities) from SCE's 2008 revenue requirement effective January 1, 2009.

$114 million increase resulting from the 2009 FERC approved rate case settlement effective March 1, 2009.

$85 million decrease primarily due to the revenue requirements for medical, dental, and vision expenses and SCE's share of Palo Verde operation and maintenance expenses, which beginning in 2009 are reflected in utility cost recovery activities.

In December 2009, the CPUC approved a payment of $26 million (compared to a $25 million payment in 2008) on SCE's 2006-2008 energy efficiency risk/reward incentive mechanism. SCE expects to recognize a final payment of approximately $27 million in 2010. The final payment, if any, may be reduced as a result of the final verification and review of the entire program cycle savings.

Higher operation and maintenance expenses of $60 million primarily due to:

$105 million of higher transmission and distribution expenses primarily due to higher costs to support system reliability and infrastructure projects, increases in preventive maintenance work, as well as engineering costs;

$50 million of higher expenses related to regulatory and performance issues including the NRC requiring SCE to take action to provide greater assurance of compliance by San Onofre personnel with applicable NRC requirements and procedures. SCE is currently implementing plans to address the identified issues (See "Item 1 Business Regulation Nuclear Power Plant Regulation" for further discussion);

$50 million of higher expenses associated with new information technology system requirements and facility maintenance to support company growth programs;

$30 million of higher expenses resulting from the transfer of the Mountainview plant to utility rate base in July 2009, previously recognized in cost-recovery activities; partially offset by

$175 million of expenses which, beginning in 2009, are recovered through balancing accounts and are reflected in 2009 cost-recovery activities. SCE's 2009 GRC decision authorized balancing account treatment for medical, dental and vision expenses and SCE's share of Palo Verde operations and maintenance expenses.

Higher depreciation expense of $80 million primarily resulting from increased capital investments including capitalized software costs.

Lower net interest expense and other of $118 million primarily due to:

Lower other expenses of $71 million primarily due to a final charge of $60 million ($49 million after-tax)recorded in 2008 resulting from the CPUC decision on SCE's PBR mechanism as well as a $14 million decrease in civic, political and related activity expenditures, primarily related to spending on Proposition 7 in 2008, partially offset by a $8 million increase in donations. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 12. Other Income and Expenses" for further detail of other expenses.

Higher other income of $63 million due to an increase in AFUDC equity earnings primarily resulting from:

$50 million increase in AFUDC equity earnings in the third quarter of 2009 related to the transfer of the Mountainview power plant to utility rate base. The 2009 CPUC GRC decision granted the authority to transfer the assets and liabilities of Mountainview Power Company, LLC to SCE, which was subsequently approved by the FERC and transferred in July 2009.

$12 million increase in AFUDC equity earnings resulting from an increase in construction work in progress related to SCE's capital investment program.

See "Item 8. Edison International Notes to Consolidated Financial Statements Note 12. Other Income and Expenses" for further detail of other income.

Higher interest expense of $8 million primarily due to higher outstanding balances on long-term debt partially offset by lower interest expense on short-term borrowings. Due to an increase in cash flow from operations, including the positive cash impact from the Global Settlement and other tax timing differences, SCE was able to defer some of its expected financings in 2009 to support its growth programs.

Lower income tax expense primarily due to an interest benefit related to the Global Settlement, partially offset by higher pre-tax income, higher 2008 software deductions resulting from the implementation of SAP, and lower property-related tax benefits in 2009.

2008 vs. 2007

Utility earning activities were primarily affected by:

Higher operating revenue of $289 million primarily due to rate base related revenue growth, and authorized energy efficiency incentives. SCE recorded $25 million of energy efficiency revenues in 2008 in connection with the energy efficiency risk/reward incentive mechanism.

Higher operation and maintenance expenses of $154 million primarily due to $60 million of higher generation expenses related to maintenance and refueling outage expenses at San Onofre and higher overhaul and outage costs at Four Corners and Palo Verde and $50 million of higher customer service expenses and administrative and general expenses

Table of Contents

primarily related to higher labor costs, increased uncollectible accounts and higher franchise fees and higher maintenance costs.

Higher depreciation expense of $95 million primarily resulting from increased capital investments, including capitalized software costs, and a $17 million cumulative depreciation rate adjustment recorded in the second quarter of 2008.

Higher net interest expense and other of $56 million primarily due to:

Higher other expenses of $79 million primarily due to a final charge of $60 million ($49 million after-tax) recorded in 2008 related to a decision received regarding SCE incentives claimed under a CPUC-approved PBR mechanism. The 2008 variance was also due to an increase of $8 million for civic, political and related activity expenditures primarily related to spending on Proposition 7.

Higher other income of $24 million primarily due to $10 million of proceeds received for corporate-owned life insurance policies and an $8 million increase in AFUDC equity earnings resulting from an increase in construction work in progress related to SCE's capital investment program.

Lower interest expense of $21 million primarily due to lower balancing account over-collections and lower interest rates applied to those over-collections. This decrease was partially offset by higher interest expense resulting from higher outstanding balances on long-term debt.

Lower interest income of $22 million primarily due to lower balancing account under-collections and lower interest rates in 2008 compared to 2007 partially offset by higher interest income due to higher cash and equivalents and short-term investment balances.

Utility Cost-Recovery Activities

2009 vs. 2008

Utility cost-recovery activities were primarily affected by:

Lower purchased power expense of $1.1 billion primarily due to: lower bilateral energy and QF purchases of $1.3 billion primarily due to lower natural gas prices and decreased kWh purchases; and lower firm transmission rights costs of $65 million due to implementation of the MRTU market. Realized losses on economic hedging activities were $344 million in 2009 and $60 million in 2008. Changes in realized losses on economic hedging activities were primarily due to settled natural gas prices being significantly lower than average fixed prices.

Lower fuel expense of $679 million primarily due to lower costs at the Mountainview plant of $230 million and lower costs for the SCE Big 4 projects of $445 million, both resulting from lower natural gas costs in 2009 compared to 2008.

Higher operation and maintenance expense of $81 million primarily related to $185 million of expenses which beginning in 2009 are recovered through balancing accounts and are reflected in 2009 cost recovery activities. SCE's 2009 GRC decision authorized balancing account treatment for medical, dental, and vision expenses and its share of Palo Verde operation and maintenance expenses. In addition, SCE recorded

Table of Contents

higher pension and PBOP expenses of $60 million due to the volatile market conditions experienced in 2008. These increases were partially offset by $50 million of lower energy efficiency costs, $85 million of lower transmission access and reliability service charges and $30 million of lower Mountainview expenses resulting from the transfer of the Mountainview plant to utility rate base in July 2009.

2008 vs. 2007

Utility cost-recovery activities were primarily affected by:

Higher purchased power expense of $610 million due to: higher bilateral energy and QF purchases of $495 million, primarily due to higher natural gas prices and increased kWh purchases and higher ISO-related energy costs of $165 million. These increases were partially offset by $30 million of lower firm transmission rights costs. Realized losses on economic hedging were $60 million in 2008 and $132 million in 2007. Changes in realized losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007.

Higher fuel expense of $209 million primarily due to higher costs at SCE's Mountainview plant of $85 million and higher costs at SCE's VIEs of $104 million, both resulting from higher natural gas prices in 2008 compared to 2007.

Supplemental Operating Revenue Information

SCE's total consolidated operating revenue was $10 billion, $11.2 billion and $10.2 billion for the year-ended December 31, 2009, 2008, and 2007, respectively, of which $9.5 billion, $9.3 billion and $9.2 billion related to retail billed and unbilled revenue (excluding wholesale sales) for the same respective periods. In 2009, retail billed and unbilled revenue increased $184 million compared to the same period in 2008. The increase reflects a rate increase (including impact of a tiered rate structure) of $564 million and a sales volume decrease of $380 million. Effective April 4, 2009, SCE's overall system average rate increased to 14.1¢ per-kWh due to the implementation of both revenue allocation and rate design changes authorized in Phase 2 of the 2009 GRC and the FERC transmission rate changes authorized in the 2009 FERC rate case. The sales volume decrease was due to the economic downturn as well as the impact of milder weather experienced in 2009 compared to the same period in 2008. Retail billed and unbilled revenue increased $94 million in 2008, compared to the same period in 2007. The increase reflects a rate increase (including impact of tiered rate structure) of $92 million and a sales volume increase of $2 million. The rate increase was due to minor variations of usage by rate class.

Due to warmer weather during the summer months and SCE's rate design, operating revenue during the third quarter of each year is generally higher than other quarters.

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 are not recognized as revenue by SCE. The amounts collected and remitted to CDWR were $1.8 billion, $2.2 billion and $2.3 billion for the years ended December 31, 2009, 2008 and 2007, respectively.

Table of Contents

Effective Income Tax Rates

SCE's effective income tax rate was 16.3% in 2009 compared to 31.8% in 2008. The effective tax rate decreased due to 2009 benefits related to both the Global Settlement and recognition of additional AFUDC equity resulting from the transfer of the Mountainview power plant to utility rate base. Partially offsetting these items was an increase from higher 2008 software deductions related to the implementation of SAP and lower property-related tax benefits in 2009. The effective tax rate for both periods was lower than the federal statutory rate primarily due to these items as well as other property related flow-through items and state income expense. The CPUC requires flow-through rate-making treatment for the current tax benefit arising from certain property-related and other temporary differences, which reverse over time. The accounting treatment for these temporary differences results in recording regulatory assets and liabilities for amounts that would otherwise be recorded to deferred income tax expense.

SCE's effective income tax rate was 31.8% in 2008 compared to 30.8% in 2007. The 2008 effective tax rate included tax benefits from higher software deductions related to the implementation of SAP. The 2007 effective tax rate included tax benefits from reductions in liabilities for uncertain tax positions to reflect both the progress made in an administrative appeals 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 effective tax rate for both periods was lower than the federal statutory rate primarily due to these items as well as other property related flow-through items and state income tax expense. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes."

LIQUIDITY AND CAPITAL RESOURCES

SCE's ability to operate its business, complete planned capital projects, and implement its business strategy is dependent upon its cash flow and access to the capital markets to finance its business. SCE's overall cash flows fluctuate based on, among other things, its ability to recover its costs in a timely manner from its customers through regulated rates, changes in commodity prices and volumes, collateral requirements, dividend payments made to Edison International, and the outcome of tax and regulatory matters.

SCE's continuing obligations and projected capital investments, both for 2010, are expected to be funded through cash and equivalents on hand, operating cash flows and incremental capital market financings of debt and preferred equity. SCE expects that it would also be able to draw on the remaining availability of its credit facilities and access capital markets if additional funding and liquidity are necessary to meet operating and capital requirements.

Available Liquidity

As of December 31, 2009, SCE had approximately $3.3 billion of available liquidity comprised of cash and equivalents and short-term investments and $2.9 billion available under credit facilities. As of December 31, 2009, SCE's long-term debt, including current maturities of long-term debt, was $6.7 billion.

Table of Contents

The following table summarizes the status of SCE's credit facilities at December 31, 2009:

(in millions)	Credit Facilities[1]
Commitment	$ 2,894
Outstanding borrowings	
Outstanding letters of credit	(12)
Amount available	$ 2,882

1 SCE has two credit facilities with various banks. A $2.4 billion five-year credit facility that matures in February 2013, with four one-year options to extend by mutual consent and a $500 million 364-day revolving credit facility terminating on March 16, 2010.

Debt Covenant

SCE has a debt covenant in its credit facilities that limits its debt to total capitalization ratio to less than or equal to 0.65 to 1. At December 31, 2009, SCE's debt to total capitalization ratio was 0.45 to 1.

Capital Investment Plan

SCE's capital investment plan for 2010 2014 includes a capital forecast of $21.5 billion. The 2010 2011 planned capital investments for projects under CPUC jurisdiction are recovered through the authorized revenue requirement in SCE's 2009 GRC or through other CPUC-authorized mechanisms. Recovery of planned capital investments for projects under CPUC jurisdiction beyond 2011 and not already approved through other CPUC-authorized mechanisms, is subject to the outcome of future CPUC GRCs or other CPUC approvals. Recovery of the 2010 planned capital investments for projects under FERC jurisdiction has been requested in the 2010 FERC Rate Case. Recovery of the 2011 2014 planned capital investments under FERC jurisdiction will be requested in future FERC transmission filings, as appropriate.

The completion of the projects, the timing of expenditures, and the associated cost recovery may be affected by permitting requirements and delays, construction schedules, availability of labor, equipment and materials, financing, legal and regulatory approvals and developments, weather and other unforeseen conditions.

SCE capital investments (including accruals) related to its 2009 capital plan were $2.9 billion. SCE's capital investments for 2009 were approximately 15% less than the original forecast, primarily due to timing delays resulting from a later than expected 2009 GRC decision and delays in other regulatory approvals. The estimated capital investments for the next five years may vary from SCE's current forecast in a range of $18 billion to $21.5 billion based on the average variability experienced in 2008 and 2009 of 16.5%. Applying the two-year historical average variability to the current forecast, the estimated capital investments for the next five years would vary in the range of: 2010 $3.3 billion to $4.0 billion; 2011 $3.7 billion to $4.4 billion; 2012 $3.9 billion to $4.6 billion; 2013 $3.6 billion to $4.3 billion; and 2014

Table of Contents

$3.5 billion to $4.2 billion. SCE's 2009 capital spending and 2010 2014 capital spending forecast is set forth in the following table:

(in millions)	2009 Actual	2010	2011	2012	2013	2014
Distribution	$ 1,732	$ 1,855	$ 1,906	$ 2,387	$ 2,324	$ 2,446
Transmission	490	652	1,300	1,391	1,179	1,020
Generation	585	789	528	580	548	538
EdisonSmartConnect™	123	496	491	74	34	15
Solar Rooftop Program	8	191	197	203	209	150
Total Estimated Capital Investments[1]	$ 2,938	$ 3,983	$ 4,422	$ 4,635	$ 4,294	$ 4,169

1 Included in SCE's capital investment plan are projected environmental capital expenditures of $510 million in 2010 and approximately $2.8 billion for the period 2011 through 2014. The projected environmental capital expenditures are to comply with laws, regulations, and other nondiscretionary requirements.

Distribution Projects

Distribution investments include projects and programs to meet customer load growth requirements, reliability and infrastructure replacement needs, information and other technology and related facility requirements for 2010 2014. Of the total investments, $3.8 billion are recovered through rates authorized in SCE's 2009 CPUC GRC decision, and $7.1 billion are subject to review and approval in the 2012 CPUC GRC proceeding.

Transmission Projects

SCE's has planned the following significant transmission projects:

Tehachapi Transmission Project An eleven segment project consisting of new and upgraded transmission lines and associated substations built primarily to enable the development of renewable energy generated primarily by wind farms in remote areas of eastern Kern County, California. Tehachapi segments one, two and a portion of segment three were completed and placed in service in 2009. The remainder of segment three is under construction and expected to be placed in service over the period 2011 2013. SCE continues to seek the necessary licensing permits for Tehachapi segments four through eleven, which are expected to be placed in service between 2011 and 2015, subject to receipt of licensing and regulatory approvals. SCE expects to invest $1.7 billion over the period 2010 2014 on this project. In November 2007, the FERC approved a 125 basis point ROE project adder, a 50 basis point incentive for CAISO participation, recovery of the ROE and incentive adders during the CWIP phase, and recovery of abandoned plant costs (if any) on this project. SCE's requested 100% CWIP cost recovery is still pending FERC approval.

Devers-Colorado River Project A transmission project, also known as the California portion of the DPV2 project, involving the installation of a high voltage (500 kV) transmission line from Romoland, California to the Colorado River switchyard west of Blythe, California. The project is currently expected to be placed in service in 2013, subject to final licensing and regulatory approvals. Over the period 2010 2014, SCE expects to invest $658 million for this project in California. The DPV2 project includes the transmission line through a portion of western Arizona, although SCE has deferred the Arizona portion while it continues to evaluate its transmission needs in western Arizona.

Table of Contents

In November 2007, the FERC approved a 125 basis point ROE project adder, a 50 basis point adder for CAISO participation, recovery of the ROE and incentive adders during the CWIP phase, and recovery of abandoned plant costs (if any) on the DPV2 project. Various parties have challenged SCE's ability to receive the DPV2 incentives.

Eldorado-Ivanpah Transmission Project A proposed 220/115 kV substation near Primm, Nevada and an upgrade of a 35-mile portion of an existing transmission line connecting the new substation to the Eldorado Substation, near Boulder City, Nevada. The project is currently expected to be placed in service in 2013, subject to necessary licensing and regulatory approvals. SCE expects to invest $469 million over the period 2010 2014 on this project. In December 2009, the FERC granted conditional approval of incentives on the project which included 100 basis point ROE project adder, a 50 basis point incentive for CAISO participation, recovery of the ROE and incentive adders during the CWIP phase, and recovery of abandoned plant costs (if any) on this project. The approval was conditioned upon the approval of the CAISO and its finding that the project ensures reliability or reduces the cost of delivered power.

Other capital investments consisting of $2.7 billion for other transmission to maintain reliability and expand capability of its infrastructure over the period 2010 2014. Included in these capital investments are other renewable projects in support of the 33% renewable procurement target.

Generation Projects

San Onofre Steam Generator Replacement Project In February 2010, SCE installed the first two of the four planned steam generators. San Onofre Unit 2 is expected to be back online in March 2010. The steam generator replacement project is intended to enable San Onofre to operate until the end of its initial license period in 2022, and beyond if license renewal proves feasible. SCE expects to spend $270 million over the period 2010 2011 on this project.

EdisonSmartConnect™

SCE's EdisonSmartConnect™ project involves installing state-of-the-art "smart" meters in approximately 5.3 million households and small businesses through its service territory. In March 2008, SCE was authorized by the CPUC to recover $1.63 billion in customer rates for the deployment phase of EdisonSmartConnect™. In 2009, SCE began full deployment of meters to all residential and small business customers under 200 kW and anticipates completion of the deployment in 2012. SCE expects to spend $1.1 billion over the period 2010 2014 on this project, with expenditures in 2013 and 2014 primarily related to post-deployment customer additions.

Solar Rooftop Program

In June 2009, the CPUC approved SCE's Solar Photovoltaic Program to develop up to 250 MW of utility-owned Solar Photovoltaic generating facilities generally ranging in size from 1 to 2 MW each, on commercial and industrial rooftops and other space in SCE's service territory. The decision allows SCE to recover its reasonable costs in customer rates and its CPUC-authorized rate of return on its investment. SCE expects to spend $1.0 billion over the period 2010 2014 on this project.

Table of Contents

Regulatory Proceedings

Cost of Capital Mechanism

In 2009, the CPUC granted SCE's request to forgo an expected 2010 cost of capital increase under the annual adjustment provision and extended SCE's existing capital structure and authorized rate of return of 11.5% through December 2012, absent any future potential annual adjustments. The revised mechanism will be subject to CPUC review in 2012 for the cost of capital set for 2013 and beyond.

2010 FERC Rate Case

On September 30, 2009, FERC issued an order allowing SCE to implement its proposed 2010 rates, subject to refund and settlement procedures, effective March 1, 2010. The proposed rates would increase SCE's revenue requirement by $107 million, or 24%, over the 2009 revenue requirement primarily due to an increase in transmission rate base and would result in an approximate 1% increase to SCE's overall system average rate. SCE is currently in settlement negotiations with the FERC staff and multiple intervenors.

Dividend Restrictions

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the 48% authorized level on a 13-month weighted average basis. At December 31, 2009, SCE's 13-month weighted-average common equity component of total capitalization was 49.8% resulting in the capacity to pay $271 million in additional dividends.

During 2009, SCE made a total of $300 million of dividend payments to its parent, Edison International and declared a $100 million dividend to Edison International which was paid in January 2010. Future dividend amounts and timing of distributions are dependent upon several factors including the actual level of capital investments, operating cash flows and earnings.

Income Tax Matters

SCE is included in the consolidated federal and combined state income tax returns of Edison International and participates in tax-allocation payments with other subsidiaries of Edison International in accordance with the terms of intercompany tax allocation agreements among the Edison International affiliated companies. Significant activities occurred during 2009 that will have an impact on SCE's future cash flows.

Global Settlement

On May 5, 2009, Edison International and the IRS finalized the terms of a Global Settlement that resolved all of SCE's federal income tax disputes and affirmative claims through tax year 2002. See "Edison International Parent and Other Liquidity and Capital Resources" for further discussion.

Table of Contents

Repair Deductions

During the fourth quarter of 2009, Edison International made a voluntary election to change its tax accounting method for certain repair costs incurred on SCE's transmission, distribution and generation assets. The change in tax accounting method resulted in an initial $192 million cash benefit realized in the fourth quarter of 2009. This benefit was based primarily on an estimated cumulative catch-up deduction for certain repair costs that were previously capitalized and depreciated over the tax depreciable life of the property. Additional information and analysis is required to determine the actual deduction that will ultimately be reflected on the 2009 income tax return (due to be filed in September 2010) which may result in additional cash benefits. The current income tax benefit from the change in accounting for repair costs represents a timing difference which will reverse over the remaining tax life of the assets. This method change did not impact SCE's 2009 results of operations. Recovery of the future increase in income taxes related to this matter is expected to be addressed in SCE's 2012 GRC. Due to the uncertainty over this recovery, SCE did not recognize an earnings benefit or regulatory asset in 2009.

Margin and Collateral Deposits

Certain derivative instruments and power procurement contracts under SCE's power and natural gas hedging activities contain collateral requirements. SCE has historically provided collateral in the form of cash and/or letters of credit for the benefit of counterparties. Collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments, and other factors. Future collateral requirements may be higher (or lower) than requirements at December 31, 2009, due to the addition of incremental power and energy procurement contracts with collateral requirements, if any, and the impact of changes in wholesale power and natural gas prices on SCE's contractual obligations.

Certain of these power contracts contain a provision that requires SCE to maintain an investment grade credit rating from the major credit rating agencies. If SCE's credit rating were to fall below investment grade, SCE may be required to pay the liability or post additional collateral. The table below illustrates the amount of collateral posted by SCE to its counterparties as well as the potential collateral that would be required as of December 31, 2009.

(in millions)

Collateral posted as of December 31, 2009[1]	$	18
Incremental collateral requirements resulting from a potential downgrade of SCE's credit rating to below investment grade		265
Total posted and potential collateral requirements[2]	$	283

1 Collateral posted consisted of $6 million in cash reflected in "Margin and collateral deposits" on the consolidated balance sheets and $12 million in letters of credit.

2 Total posted and potential collateral requirements may increase by an additional $62 million, based on SCE's forward position as of December 31, 2009, due to adverse market price movements over the remaining life of the existing contracts using a 95% confidence level.

Table of Contents

In the table above, there was zero collateral posted as of December 31, 2009 related to derivative liabilities, and $4 million of incremental collateral requirements related to derivative liabilities.

SCE's incremental collateral requirements are expected to be met from liquidity available from cash on hand and available capacity under SCE's credit facilities, discussed above.

Historical Consolidated Cash Flow

The section of the MD&A discusses consolidated cash flows from operating, financing and investing activities.

Condensed Consolidated Statement of Cash Flows

(in millions)	**2009**	**2008**	**2007**
Cash flows provided by operating activities	$ 4,069	$ 1,622	$ 2,973
Cash flows provided (used) by financing activities	(1,999)	2,024	(438)
Net cash used by investing activities	(3,219)	(2,287)	(2,366)
Net increase (decrease) in cash and equivalents	$ (1,149)	$ 1,359	$ 169

Cash Flows Provided by Operating Activities

The $2.4 billion increase in 2009 cash flows provided by operating activities over 2008 was primarily due to the following:

- $875 million cash inflow due to the receipt of tax-allocation payments due to Global Settlement related to the settlement of affirmative claims; a portion of which is timing and will be payable in future periods (See "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes" for further discussion).

- $468 million net cash inflow due to the increase in balancing account cash flows comprised of:

  - $1.3 billion net cash inflow due to the increase in ERRA balancing account cash flows (collections of approximately $450 million in 2009, compared to refunds of approximately $840 million in 2008). The ERRA balancing account was over-collected by $46 million, under-collected by $406 million and over-collected by $433 million at December 31, 2009, 2008, and 2007, respectively; partially offset by

  - $820 million net cash outflow related to all other regulatory balancing accounts which was primarily due to increased spending in 2009 compared to 2008 for public purpose and solar initiative programs and increased pension and PBOP contributions. In addition, a $200 million refund payment was received in 2008 related to public purpose programs.

- $250 million cash inflow benefit related to the American Recovery and Reinvestment Act of 2009 50% bonus depreciation provision.

- $192 million cash inflow benefit related to the change in its tax accounting method for certain repair costs incurred on SCE's transmission, distribution and generation assets.

Table of Contents

Higher cash inflow due to the increase in pre-tax income primarily driven by higher authorized revenue requirements resulting from the implementation of the 2009 CPUC and FERC GRC decisions.

Timing of cash receipts and disbursements related to working capital items.

The $1.3 billion decrease in 2008 cash flows provided by operating activities over 2007 was primarily due to the following:

$295 million net cash outflow due to the decrease in balancing account cash flows comprised of:

$745 million net cash outflow due to the decrease in ERRA balancing account cash flows (refunds of approximately $840 million in 2008, compared to refunds of approximately $95 million in 2007). The ERRA balancing account was under-collected by $406 million, over-collected by $433 million and over-collected by $526 million at December 31, 2008, 2007, and 2006, respectively; partially offset by

$450 million net cash inflow related to all other regulatory balancing accounts which was primarily due a $200 million refund payment received in 2008 related to public purpose programs, $100 million refunded to ratepayers as a result of SCE's PBR decision, and a net $150 million in other balancing account overcollections.

$240 million cash outflow due to the elimination of amounts collected in 2008 for the repayment of SCE rate reduction bonds. These bonds were fully repaid in December 2007. The bond payment is reflected in financing activities.

Timing of cash receipts and disbursements related to working capital items, including tax-related items.

Cash Flows Provided (Used) by Financing Activities

Cash provided (used) by financing activities mainly consisted of net repayments of short-term debt and long-term debt issuances (payments).

Cash used by financing activities for 2009 was $2.0 billion consisting of the following significant events:

Repaid a net $1.9 billion of short-term debt, primarily due to the improvement in economic conditions that occurred during the second half of 2008.

Paid $300 million in dividends to Edison International.

Purchased $219 million of two issues of tax-exempt pollution control bonds and converted the issues to a variable rate structure. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.

Repaid $150 million of first and refunding mortgage bonds.

Issued $500 million of first refunding mortgage bonds due in 2039 and $250 million of first and refunding mortgage bonds due in 2014. The bond proceeds were used for general corporate purposes and to finance fuel inventories.

Table of Contents

Cash provided by financing activities for 2008 was $2.0 billion consisting of the following significant events:

Borrowed $1.4 billion under the line of credit to increase SCE's cash position to meet working capital requirements, if needed, during uncertainty over economic conditions during the second half of 2008.

Issued $600 million of first 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.

Issued $500 million of 5.75% first and refunding mortgage bonds due in 2014. The proceeds were used for general corporate purposes.

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.

Paid $325 million in dividends to Edison International.

Purchased $212 million of its auction rate bonds, converted the issue to a variable rate structure, and terminated the FGIC insurance policy. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.

Paid $36 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Cash used by financing activities in 2007 was $438 million consisting of the following significant events:

Repaid $246 million of the remaining outstanding balance of its rate reduction bonds.

Paid $135 million in dividends to Edison International.

Paid $135 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Issued $500 million of short-term debt to fund interim working capital requirements.

Net Cash Used by Investing Activities

Cash flows from investing activities are driven primarily by capital expenditures and funding of nuclear decommissioning trusts. Capital expenditures were $3.0 billion, $2.3 billion and $2.3 billion for 2009, 2008 and 2007, respectively, primarily related to transmission and distribution investments. Net purchases of nuclear decommissioning trust investments and other were $199 million, $7 million and $133 million for 2009, 2008 and 2007, respectively.

Table of Contents

Contractual Obligations and Contingencies

Contractual Obligations

SCE's contractual obligations as of December 31, 2009, for the years 2010 through 2014 and thereafter are estimated below.

(in millions)	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt maturities and interest[1]	$ 13,487	$ 604	$ 708	$ 1,716	$ 10,459
Operating lease obligations[2]	12,076	779	1,550	1,557	8,190
Capital lease obligations[3]	235	8	11	13	203
Purchase obligations[4]:					
Fuel supply contract payments	1,384	180	322	291	591
Purchased-power capacity payments	6,837	395	1,024	1,384	4,034
Other commitments	45	6	12	13	14
Employee benefit plans contributions[5]	124	124			
Total[6,7]	$ 34,188	$ 2,096	$ 3,627	$ 4,974	$ 23,491

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 3. Liabilities and Lines of Credit." Amount includes interest payments totaling $7 billion over applicable period of the debt.

2 At December 31, 2009, minimum operating lease payments were primarily related to power contracts, vehicles, office space and other equipment. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

3 At December 31, 2009, minimum capital lease payments were primarily related to power purchased contracts that meet the requirements for capital leases. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

4 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

5 Amount includes estimated contributions to the pension and PBOP plans. The estimated contributions for SCE are not available beyond 2010. Due to the volatile market conditions experienced in 2008 and the decline in value of SCE's trusts, SCE's contributions increased in 2009. Based on pension and PBOP plan assets at December 31, 2009 SCE expects a decrease in contributions in 2010 but cannot predict or estimate contributions beyond 2010. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Compensation and Benefit Plans" for further information.

6 At December 31, 2009, SCE had a total net liability recorded for uncertain tax positions of $458 million, which is excluded from the table. SCE cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the IRS.

7 The contractual obligations table does not include derivative obligations and asset retirement obligations, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Derivative Instruments and Hedging Activities," and "Item 8. Edison International Notes to Consolidated Financial Statements Note 8. Property and Plant," respectively.

Contingencies

SCE has contingencies related to FERC transmission incentives and CWIP proceedings, the Navajo Nation Litigation, nuclear insurance, and spent nuclear fuel, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

Table of Contents

Environmental Remediation

SCE 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. SCE 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, SCE records the lower end of this reasonably likely range of costs (classified as "Other long-term liabilities") at undiscounted amounts.

As of December 31, 2009, SCE identified 23 sites for remediation and recorded an estimated minimum liability of $39 million of which $5 million was related to San Onofre. SCE expects to recover 90% of its remediation costs at certain sites. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies" for further discussion.

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 financing and short-term investing activities used for liquidity purposes, to fund business operations and to fund capital investments. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. In addition, SCE's authorized return on common equity (11.5% for 2010, 2009 and 2008), which is established in SCE's cost of capital proceeding, is set on the basis of forecasts of interest rates and other factors. Variances in actual financing costs compared to authorized financing costs impact earnings either positively or negatively.

At December 31, 2009, the fair market value of SCE's long-term debt (including current portion of long-term debt) was $7.2 billion, compared to a carrying value of $6.7 billion. A 10% increase in market interest rates would have resulted in a $345 million decrease in the fair market value of SCE's long-term debt. A 10% decrease in market interest rates would have resulted in a $380 million increase in the fair market value of SCE's long-term debt.

Commodity Price Risk

SCE is exposed to commodity price risk which represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's hedging program

Table of Contents

reduces ratepayer exposure to variability in market prices related to SCE's power and gas activities. SCE recovers its related hedging costs, through the ERRA balancing account, subject to reasonableness review, and as a result, exposure to commodity price is not expected to impact earnings, but may impact cash flows.

Electricity price exposure arises from the following activities:

Energy purchased and sold in the MRTU market as a result of differences between SCE's load requirements versus the amount of energy delivered from SCE's generating facilities, existing bilateral contracts, and CDWR contracts allocated to SCE. In March 2009, SCE began participating in the MRTU day-ahead and real-time markets which uses nodal locational marginal prices and is subject to price caps. The volume purchased in the MRTU market may vary due to outages at SCE's generating facilities, new or expired bilateral contracts and changes in customer demand resulting from, among other things, growth or decline in customer base and weather.

Natural gas price exposure arises from the following activities:

Natural gas purchased for generation at Mountainview and peaker plants. The volume purchased may vary due to outages and dispatch based on SCE's management of its load requirements.

Bilateral contracts where pricing is based on natural gas prices. Contract energy prices for some QFs are based on the monthly index price of natural gas delivered at the Southern California border. Approximately 37% of SCE's purchased power supply is subject to natural gas price volatility.

Power contracts in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements. Volume may vary due to dispatch based on SCE's management of its load requirements or if the existing CDWR power contracts, which have related natural gas supply contracts, are novated or replaced and SCE becomes a party to such contracts. SCE is currently unable to predict which or how many existing CDWR contracts will be novated or replaced. However, due to the expected recovery through regulatory mechanisms these power procurement expenses are not expected to affect earnings.

Natural Gas and Electricity Price Risk

SCE's hedging program reduces ratepayer exposure to variability in market prices. As part of this program, SCE enters into energy options, swaps, forward arrangements, tolling arrangements, and congestion revenue rights (CRRs). The transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. In addition, SCE's risk management committee monitors exposure related to these instruments.

SCE records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale or are classified as VIEs or leases. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes are expected to be recovered from or refunded to customers through regulatory mechanisms and therefore, SCE's fair value changes have no impact on purchased-power expense or earnings. SCE does not use hedge accounting for these transactions due to this regulatory accounting treatment.

Table of Contents

Fair Value of Derivative Instruments

SCE follows the authoritative accounting guidance for fair value measurements. For further discussion see "Item 8. Edison International Notes to Consolidated Financial Statements Note 10. Fair Value Measurements." The following table summarizes the fair values of outstanding derivative instruments used at SCE to mitigate its exposure to spot market prices:

	December 31, 2009		December 31, 2008	
(in millions)	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Electricity options, swaps and forward arrangements	$ 1	$ 25	$ 7	$ 15
Natural gas options, swaps and forward arrangements	86	171	80	304
Congestion revenue rights and firm transmission rights[1]	217		81	
Tolling arrangements[2]	43	402	63	647
Netting and collateral				(72)
Total	$ 347	$ 598	$ 231	$ 894

1 The CAISO created a commodity, CRRs, which entitles the holder to receive (or pay) the value to transmission congestion between specific nodes, acting as an economic hedge against transmission congestion charges. In September 2007 and November 2008, the CAISO allocated CRRs for the period April 2009 through December 2017 based on SCE's load requirements. In addition, SCE participated in CAISO auctions for the procurement of additional CRRs. The CRRs meet the definition of a derivative.

2 In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced agreements with different project developers who have agreed to construct new southern California generating resources. The contracts provide for fixed capacity payments as well as pricing for energy delivered based on a heat rate and contractual operation and maintenance prices. However, due to uncertainty regarding the availability of required emission credits, some of the generating resources may not be constructed and the contracts associated with these resources could therefore terminate, at which time SCE would no longer account for these contracts as derivatives.

(in millions)	
Fair value of derivative contracts, net at January 1, 2009	$ (663)
Total realized/unrealized net gains:	
Included in regulatory assets and liabilities[1]	126
Purchases and settlements, net	358
Netting and collateral	(72)
Fair value of derivative contracts, net at December 31, 2009	$ (251)

1 Due to regulatory mechanisms, SCE's realized and unrealized gains and losses are recorded as regulatory assets and liabilities.

SCE recognizes realized gains and losses on derivative instruments as purchased power expense and recovers these costs from ratepayers. As a result, realized gains and losses do not affect earnings, but may temporarily affect cash flows. Due to expected future recovery from ratepayers, unrealized gains and losses are deferred and are not recognized as purchased power expense, and therefore do not affect earnings. Realized losses on economic hedging activities were primarily due to settled natural gas prices being significantly lower than transactional average fixed prices. Unrealized gains on economic hedging activities were primarily due to changes in the expected forward prices of the CRRs, the rising volatilities related to SCE's contracts from the new generation contracts, and settlement of gas contracts during the period.

Table of Contents

The following table summarizes the increase or decrease to the fair values of outstanding derivative financial instruments as of December 31, 2009, if the electricity prices or gas prices were changed while leaving all other assumptions constant:

(in millions)	Increase in electricity prices by 10%	Decrease in electricity prices by 10%	Increase in gas prices by 10%	Decrease in gas prices by 10%
Electricity options, swaps and forward arrangements	$ 49	$ (57)	$ (28)	$ 43
Natural gas options, swaps and forward arrangements			113	(97)
Congestion revenue rights and firm transmission rights	8	(6)		
Tolling arrangements	475	(385)	(207)	288

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. 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.

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. 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.

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 (derivative assets less derivative liabilities) 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.

Table of Contents

As of December 31, 2009, the amount of balance sheet exposure as described above, broken down by the credit ratings of SCE's counterparties, was as follows:

	December 31, 2009		
(in millions)	**Exposure[2]**	**Collateral**	**Net Exposure**
S&P Credit Rating[1]			
A or higher	$ 83	$ (4)	$ 79
A-	221		221
BBB+	1		1
BBB	1		1
BBB-			
Below investment grade and not rated			
Total	$ 306	$ (4)	$ 302

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 $7 million of net account receivables and $299 million representing the fair value, adjusted for counterparty credit reserves, of derivative contracts.

The CAISO comprises 72% of the total net exposure above and is mainly related to the CRRs' fair value (see " Commodity Price Risk" for further information).

Table of Contents

EDISON MISSION GROUP

RESULTS OF OPERATIONS

The following section includes a discussion of the results of operations for the "competitive power generation" (EME) segment and the "financial services and other" (Edison Capital and other EMG subsidiaries) segment. Included in the competitive power generation segment are the activities of MEHC, the holding company of EME. MEHC's only substantive activities were its obligations under senior secured notes which were paid in full on June 25, 2007. MEHC does not have any substantive operations.

	For the Years Ended December 31,		
(in millions)	**2009**	**2008**	**2007**
Competitive power generation net income	$ 203	$ 501	$ 340
Financial services and other net income	(598)	60	70
EMG net income	$ (395)	$ 561	410
Core Earnings[1]	$ 222	$ 561	$ 560
Non-Core Earnings:			
Global Settlement	(610)		
Early Debt Retirement			(148)
Discontinued Operations	(7)		(2)
Total EMG GAAP Earnings	$ (395)	$ 561	$ 410

1 See use of Non-GAAP financial measure in "Edison International Overview Highlights of Operating Results."

Competitive Power Generation (EME) Results of Continuing Operations

This section discusses operating results in 2009, 2008 and 2007. EME's continuing operations primarily include the fossil-fueled facilities, renewable energy and gas-fired projects, energy trading, and gas-fired projects under contract, corporate interest expense and general and administrative expenses. EME's discontinued operations include all international operations, except the Doga project.

Table of Contents

The following table is a summary of competitive power generation results of operations for the periods indicated.

(in millions)	For the Years Ended December 31, 2009	2008	2007
Competitive power generation operating revenue	$ 2,377	$ 2,811	$ 2,580
Fuel	796	747	684
Other operation and maintenance	952	1,004	969
Depreciation, decommissioning and amortization	236	194	162
Lease terminations and other	4	14	1
Total operating expenses	1,988	1,959	1,816
Operating Income	389	852	764
Interest and dividend income	19	36	98
Equity in income from partnerships and unconsolidated subsidiaries net	100	122	200
Other income	5	12	6
Interest expense net of amounts capitalized	(296)	(279)	(313)
Loss on early extinguishment of debt			(241)
Income from continuing operations before income taxes	217	743	514
Income tax expense	10	243	173
Income from continuing operations	207	500	341
Loss from discontinued operations net of tax	(7)	1	(2)
Net income	200	501	339
Less: Loss attributable to noncontrolling interests	(3)		(1)
Competitive power generation net income attributable to Edison International	$ 203	$ 501	$ 340

Adjusted Operating Income (AOI) Overview

The following section and table provide a summary of results of EME's operating projects and corporate expenses for the three years ended December 31, 2009, together with discussions of the contributions by specific projects and of other significant factors affecting these results.

Table of Contents

The following table shows the AOI of EME's projects:

(in millions)	Years Ended December 31, 2009	2008	2007
Midwest Generation plants	$ 340	$ 688	$ 583
Homer City facilities	186	202	221
Renewable energy projects	53	60	31
Energy trading	49	164	142
Big 4 projects	46	87	147
Sunrise	37	24	33
Doga	8	8	14
March Point	11		
Westside projects	4	9	11
Other projects	9	13	13
Other operating income (expense)		(31)	(6)
	743	1,224	1,189
Corporate administrative and general	(163)	(172)	(169)
Corporate depreciation and amortization	(15)	(12)	(8)
AOI[1]	$ 565	$ 1,040	$ 1,012

The following table reconciles AOI to operating income as reflected on EME's consolidated statements of income.

(in millions)	Years Ended December 31, 2009	2008	2007
AOI	$ 565	$ 1,040	$ 1,012
Less:			
Equity in earnings of unconsolidated affiliates	100	122	200
Dividend income from projects	12	10	12
Production tax credits	56	44	29
Other income, net	5	12	6
Net loss attributable to noncontrolling interests	3		1
Operating Income	$ 389	$ 852	$ 764

1 AOI is equal to operating income under GAAP, plus equity in earnings of unconsolidated affiliates, dividend income from projects, production tax credits, other income and expenses, and net (income) loss attributable to noncontrolling interests. Production tax credits are recognized as wind energy is generated based on a per-kilowatt-hour rate prescribed in applicable federal and state statutes. AOI is a non-GAAP performance measure and may not be comparable to those of other companies. Management believes that inclusion of earnings of unconsolidated affiliates, dividend income from projects, production tax credits, other income and expenses, and net (income) loss attributable to noncontrolling interests in AOI is meaningful for investors as these components are integral to the operating results of EME.

Table of Contents

Adjusted Operating Income from Consolidated Operations

Midwest Generation Plants

The following table presents additional data for the Midwest Generation plants:

(in millions)	Years Ended December 31 2009	2008	2007
Operating Revenues	$ 1,487	$ 1,778	$ 1,579
Operating Expenses			
Fuel[1]	547	482	400
Gain on sale of emission allowances[2]	(1)	(3)	(18)
Plant operations	397	434	420
Plant operating leases	75	75	75
Depreciation and amortization	109	106	99
(Gain) on buyout of contract and (gain) loss on disposal of assets	2	(16)	
Administrative and general	21	22	22
Total operating expenses	1,150	1,100	998
Operating Income	337	678	581
Other Income	3	10	2
AOI	$ 340	$ 688	$ 583
Statistics			
Generation (in GWh):			
Energy only contracts	28,977	26,010	22,503
Load requirements services contracts	1,333	5,090	7,458
Total	30,310	31,100	29,961

1 Included in fuel costs were $63 million, $5 million and $5 million in 2009, 2008 and 2007, respectively, related to the net cost of emission allowances. Midwest Generation purchased NO_x emission allowances from Homer City at fair market value. Purchases were $1 million and $0.4 million in 2009 and 2007, respectively. There were no purchases in 2008. For more information regarding the price of emission allowances, see "EMG: Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk."

2 Midwest Generation sold excess SO_2 emission allowances to Homer City at fair market value. Sales to Homer City were $2 million in 2008 and $21 million in 2007. There were no sales in 2009. These sales reduced operating expenses. Midwest Generation recorded $3 million of intercompany profit during 2008 consisting of $1 million and $2 million on emission allowances sold by Midwest Generation to Homer City during the first quarter of 2008 and the fourth quarter of 2007, respectively, but not yet used by Homer City until the second quarter of 2008 and the first quarter of 2008, respectively. In addition, Midwest Generation recorded $4 million of intercompany profit during 2007 that was eliminated by Midwest Generation in 2006 on emission allowances sold by Midwest Generation to Homer City in the fourth quarter of 2006 but not used by Homer City until the first quarter of 2007.

AOI from the Midwest Generation plants decreased $348 million in 2009 compared to 2008, and increased $105 million in 2008 compared to 2007. The 2009 decrease in AOI was

Table of Contents

primarily attributable to a decline in realized gross margin, partially offset by an increase in unrealized gains related to hedge contracts (described below), and lower plant operations expense. The decline in realized gross margin was primarily due to a 21% decline in average realized energy prices resulting from lower energy prices and higher fuel costs to comply with the CAIR annual NO_x emission program that began in 2009 and to implement new mercury emission controls. This decline was partially offset by higher capacity revenue primarily due to higher capacity prices from the RPM auctions. Plant operations expense was lower in 2009 as compared to 2008 due to cost containment efforts and the deferral of plant overhaul activities.

The 2008 increase in AOI was primarily attributable to higher realized gross margin, an increase in unrealized gains related to hedge contracts (described below) and a $15 million gain recorded during the first quarter of 2008 related to a buyout of a fuel contract. The increase in realized gross margin was due to an increase in capacity prices as a result of the RPM auctions. The increase in generation and slightly higher average realized energy prices was partially offset by higher coal and transportation costs.

Included in operating revenues were unrealized gains (losses) of $30 million, $(6) million and $(25) million in 2009, 2008 and 2007, respectively. Unrealized gains in 2009 were primarily due to hedge contracts that are not accounted for as cash flow hedges (referred to as economic hedges). In addition, $14 million was reversed from accumulated other comprehensive income and recognized in 2009 related to the power contracts with Lehman Brothers Commodity Services, Inc. Unrealized losses in 2008 included a $24 million write-down of power contracts with Lehman Brothers Commodity Services, Inc. for 2009 and 2010 generation. These contracts qualified as cash flow hedges until EME dedesignated the contracts due to nonperformance risk and subsequently terminated the contracts. The change in fair value was recorded as an unrealized loss during 2008. In addition, unrealized gains (losses) included the ineffective portion of hedge contracts at the Midwest Generation plants attributable to changes in the difference between energy prices at NiHub (the settlement point under forward contracts) and the energy prices at the Midwest Generation plants busbars (the delivery point where power generated by the Midwest Generation plants is delivered into the transmission system) resulting from marginal losses. Unrealized losses in 2007 were also attributable to energy contracts that were entered into to hedge the price risk related to projected sales of power. During 2007, power prices increased resulting in mark-to-market losses on economic hedges.

Included in fuel expenses were unrealized gains of $15 million for the year ended December 31, 2009 due to oil futures contracts that were accounted for as economic hedges. The contracts were entered into in 2009 to hedge a portion of a fuel adjustment provision of a rail transportation contract. For more information regarding forward market prices and unrealized gains (losses), see "EMG: Market Risk Exposures Commodity Price Risk" and "EMG: Results of Operations Accounting for Derivative Instruments," respectively.

Table of Contents

Homer City

The following table presents additional data for the Homer City facilities:

(in millions)	Years Ended December 31, 2009	2008	2007
Operating Revenues	$ 663	$ 717	$ 764
Operating Expenses			
Fuel[1]	251	270	306
Loss on sale of emission allowances	1		
Plant operations	102	126	119
Plant operating leases	102	102	102
Depreciation and amortization	16	16	14
Loss on sale of assets	1		
Administrative and general	4	4	4
Total operating expenses	477	518	545
Operating Income	186	199	219
Other Income		3	2
AOI	$ 186	$ 202	$ 221
Statistics			
Generation (in GWh)	11,446	11,334	13,649

[1] Included in fuel costs were $16 million, $20 million and $31 million in 2009, 2008 and 2007, respectively, related to the net cost of emission allowances. Homer City purchased SO_2 emission allowances from Midwest Generation at fair market value. Purchases were $2 million in 2008 and $21 million in 2007. There were no purchases in 2009. For more information regarding the price of emission allowances, see "EMG: Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk."

AOI from the Homer City facilities decreased $16 million in 2009 compared to 2008 and $19 million in 2008 compared to 2007. The 2009 decrease in AOI was primarily attributable to a decline in realized gross margin partially offset by lower plant operations expense. The decline in realized gross margin was primarily due to a 13% decline in average realized energy prices, partially offset by an increase in capacity revenues and lower coal costs. The decline in plant operations expense was due to cost containment efforts and the deferral of plant overhaul activities.

The 2008 decrease in AOI compared to 2007 was primarily attributable to lower realized gross margin and higher plant maintenance expenses, partially offset by an increase in unrealized gains related to hedge contracts (described below). The decline in realized gross margin was due to lower generation from higher forced outages, lower off-peak dispatch and extended planned overhauls in 2008, partially offset by an increase in capacity revenues and the sale of excess coal inventory.

Included in operating revenues were unrealized gains (losses) from hedge activities of $15 million, $21 million and $(10) million in 2009, 2008 and 2007, respectively. Unrealized gains (losses) were primarily attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges. The ineffective portion of

Table of Contents

hedge contracts at Homer City was attributable to changes in the difference between energy prices at PJM West Hub (the settlement point under forward contracts) and the energy prices at the Homer City busbar (the delivery point where power generated by the Homer City facilities is delivered into the transmission system). For more information regarding forward market prices and unrealized gains (losses), see "EMG: Market Risk Exposures Commodity Price Risk" and "EMG: Results of Operations Accounting for Derivative Instruments," respectively.

Non-GAAP Disclosures Fossil-Fueled Facilities

Adjusted Operating Income (Loss)

AOI is equal to operating income plus other income (expense) for the fossil-fueled facilities. AOI is a non-GAAP performance measure and may not be comparable to those of other companies. Management believes that inclusion of other income (expense) is meaningful for investors as the components of other income (expense) are integral to the results of the fossil-fueled facilities.

Seasonal Disclosure Fossil-Fueled Facilities

In 2009, the seasonal fluctuations in electric demand normally occurring for the fossil-fueled facilities were minimized by milder winter conditions and cooler than normal summer months. Normally, due to fluctuations in electric demand resulting from warmer weather during the summer months and cold weather during the winter months, electric revenues from the fossil-fueled 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, AOI from the fossil-fueled facilities are seasonal and have significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. For further discussion regarding market prices, see "EMG: Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Fossil-Fueled Facilities."

Table of Contents

Renewable Energy Projects

The following table presents additional data for EME's renewable energy projects:

(in millions)	Years Ended December 31, 2009	2008	2007
Operating Revenues	$ 141	$ 108	$ 51
Production Tax Credits	56	44	29
	197	152	80
Operating Expenses			
Plant operations	55	35	18
Depreciation and amortization	92	59	34
Administrative and general	3	2	1
Total operating expenses	150	96	53
Other Income	3	4	3
Net Loss Attributable to Noncontrolling Interests	3		1
AOI[1]	$ 53	$ 60	$ 31
Statistics			
Generation (in GWh)	3,081	2,286	1,533

1 AOI is equal to operating income (loss) plus production tax credits, other income and expense, and net (income) loss attributable to noncontrolling interests. Production tax credits are recognized as wind energy is generated based upon a per-kilowatt-hour rate prescribed in applicable federal and state statutes. Under GAAP, production tax credits generated by wind projects are recorded as a reduction in income taxes. Accordingly, AOI represents a non-GAAP performance measure which may not be comparable to those of other companies. Management believes that inclusion of production tax credits in AOI for wind projects is meaningful for investors as federal and state subsidies are an integral part of the economics of these projects. The following table reconciles AOI as shown above to operating income (loss) under GAAP:

(in millions)	Years Ended December 31 2009	2008	2007
AOI	$ 53	$ 60	$ 31
Less:			
Production tax credits	56	44	29
Other income	3	4	3
Net loss attributable to noncontrolling interests	3		1
Operating Income (Loss)	$ (9)	$ 12	$ (2)

AOI from renewable energy projects decreased $7 million in 2009 compared to 2008, and increased $29 million in 2008 compared to 2007. The 2009 decrease in AOI was primarily attributable to mild wind conditions, which reduced the revenue increases relative to the increased operating costs associated with additional projects coming on line. Expenses incurred for projects under construction also contributed to the decrease in AOI. New projects that commenced operations were the primary drivers for increases in the revenues and operating costs and AOI in 2008. EME's share of installed capacity of new wind projects that commenced operations during 2009, 2008 and 2007 was 223 MW, 396 MW and 292 MW, respectively.

98

Table of Contents

Energy Trading

EME seeks to generate profit by utilizing its subsidiary, EMMT, to engage in trading activities in those markets in which it is active as a result of its management of the merchant power plants of Midwest Generation and Homer City. EMMT trades power, fuel, and transmission congestion primarily in the eastern U.S. power grid using products available over the counter, through exchanges, and from ISOs. AOI from energy trading activities decreased $115 million in 2009 compared to 2008, and increased $22 million in 2008 compared to 2007. The 2009 decrease in AOI from energy trading activities was attributable to lower transmission congestion in the eastern U.S. power grid. The 2008 increase in AOI from energy trading activities was primarily attributable to increased transmission congestion and market volatility in key markets. In addition, energy trading included favorable results for load service transactions in 2009 and 2008.

Adjusted Operating Income from Unconsolidated Affiliates

Big 4 Projects

AOI from the Big 4 projects decreased $41 million in 2009 compared to 2008, and $60 million in 2008 compared to 2007. The 2009 decrease in AOI was primarily due to lower natural gas prices affecting electricity and steam revenues. The 2008 decrease in AOI was primarily due to $60 million in lower AOI from the Sycamore and Watson projects as a result of lower pricing in 2008 than previously applied under a long-term power sales agreement that expired.

Sunrise

AOI from the Sunrise project increased $13 million in 2009 from 2008 and decreased $9 million in 2008 from 2007. The 2009 increase was primarily due to higher availability incentive payments in 2009 and lower maintenance expenses. The 2008 decrease was primarily due to lower availability incentive payments in 2008 and higher maintenance expenses due to unplanned outages in 2008.

March Point

In 2009, EME recommenced recording its share of equity in income from the March Point project and recorded $11 million for the year. Although EME's investment in the project was determined to be fully impaired in 2005, declining natural gas prices reduced fuel expenses and returned the project to profitability. To the extent that cash is received from the project in excess of EME's investment, such amount will be included in equity in income from unconsolidated affiliates on EME's consolidated statements of income. In February 2010, EME received an $18 million equity distribution from the March Point project. EME subsequently sold its ownership interest in the March Point project to its partner.

Seasonal Disclosure Unconsolidated Affiliates

EME's third quarter equity in income from its unconsolidated energy projects is normally higher than equity in income related to other quarters of the year due to seasonal fluctuations and higher energy contract prices during the summer months.

Table of Contents

Other Operating Income (Expense)

Other operating income (expense) in 2009 included a small gain on the sale of a portion of EME's solar project development pipeline, offset by a write-down of capitalized costs related to a development project during the fourth quarter of 2009. Other operating income (expense) in 2008 resulted from a charge of $23 million related to the termination of a turbine supply agreement in connection with the Walnut Creek project and a $7 million write-down of capitalized costs related to U.S. Wind Force. These amounts are reflected in "Gain on buyout of contract, loss on termination of contract, asset write-down and other charges and credits" on EME's consolidated statements of income.

Interest Related Income (Expense)

	Years Ended December 31,		
(in millions)	**2009**	**2008**	**2007**
Interest income	$ 7	$ 26	$ 85
Interest expense:			
EME debt	(267)	(254)	(215)
Non-recourse debt:			
Midwest Generation	(7)	(14)	(45)
EME Funding			(2)
EME CP Holding Co.	(5)	(5)	(6)
Viento Funding II, Inc.[1]	(9)		
Other projects	(8)	(6)	(5)
	$ (296)	$ (279)	$ (273)
Loss on early extinguishment of debt	$	$	$ (241)

1 In June 2009, a subsidiary of EME, Viento Funding II, Inc., completed a non-recourse financing of EME's interests in the Wildorado, San Juan Mesa and Elkhorn Ridge wind projects.

Interest income decreased $19 million in 2009 from 2008 and $59 million in 2008 from 2007. The 2009 decrease was primarily attributable to lower interest rates in 2009 compared to 2008. The 2008 decrease was primarily attributable to lower interest rates in 2008, compared to 2007, and lower average cash equivalents and short-term investment balances.

EME's interest expense to third parties, before capitalized interest, increased $4 million in 2009 from 2008 and $14 million in 2008 from 2007. The 2009 increase was primarily due to higher debt balances under EME's credit facility in 2009, compared to 2008, and EME's wind financing in June 2009. The 2008 increase primarily resulted from EME's refinancing activities in May 2007.

Loss on early extinguishment of debt was $241 million in 2007 related to the early repayment of EME's 7.73% senior notes due June 15, 2009 and Midwest Generation's 8.75% second priority senior secured notes due May 1, 2034 and MEHC's 13.5% senior secured notes due July 15, 2008.

Table of Contents

Income Taxes

Competitive power generation (including MEHC) effective tax rates were 5%, 33% and 34%, respectively, for the years ended December 31, 2009, 2008 and 2007. The effective tax rate for 2009 was impacted by lower pretax income in relation to the level of production tax credits and estimated state income tax benefits allocated from Edison International. Production tax credits for wind projects of $56 million, $44 million and $29 million were recognized for the years ended December 31, 2009, 2008 and 2007, respectively. Estimated state income tax benefits allocated from Edison International of $15 million, $5 million and $10 million were recognized for the years ended December 31, 2009, 2008 and 2007, respectively. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes."

In May 2009, Edison International and the Internal Revenue Service completed a settlement of federal tax disputes and affirmative claims for open tax years 1986 through 2002. As a result, state tax years for the same periods are now open pending review by state taxing authorities of agreed final federal adjustments. The settlement includes the resolution of issues pertaining to EME which were largely timing in nature. During the second quarter of 2009, EME recorded an income tax benefit of $6 million due to the settlement and related estimated impact of interest and state income taxes. The amount recorded is subject to change based on the final determination of interest and state taxes and items affected under the tax-allocation agreement.

Results of Discontinued Operations

Loss from discontinued operations, net of tax, increased $8 million in 2009 compared to 2008. Results in 2009 and 2008 included foreign exchange gains (losses) and interest expense associated with contract indemnities related to EME's sale of international projects in December 2004. In addition, EME increased its estimated liability for a tax indemnity by $6 million during the second quarter of 2009.

Related-Party Transactions

EME owns interests in partnerships that sold electricity generated by their project facilities to SCE and others under the terms of power purchase agreements. Sales by these partnerships to SCE under these agreements amounted to $366 million, $686 million and $747 million in 2009, 2008 and 2007, respectively.

Accounting for Derivative Instruments

EME uses derivative instruments to reduce its exposure to market risks that arise from fluctuations in the prices of electricity, capacity, fuel, emission allowances, and transmission rights. For derivative instruments recorded at fair value, changes in fair value are recognized in earnings at the end of each accounting period unless the instrument qualifies for hedge accounting. For derivatives that 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.

Table of Contents

EME classifies unrealized gains and losses from derivative instruments as part of operating revenues or fuel expenses. 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 three-year period ended December 31, 2009:

	Years Ended December 31,		
(in millions)	**2009**	**2008**	**2007**
Midwest Generation plants			
Non-qualifying hedges	$ 40	$ (16)	$ (14)
Ineffective portion of cash flow hedges	5	10	(11)
Homer City facilities			
Non-qualifying hedges	1	1	(1)
Ineffective portion of cash flow hedges	14	20	(9)
Total unrealized gains (losses)	$ 60	$ 15	$ (35)

At December 31, 2009, unrealized gains of $47 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to subsequent periods ($40 million for 2010 and $7 million for 2011).

Fair Value of Derivative Instruments

In determining the fair value of EME's derivative positions, EME uses third-party market pricing where available. For further explanation of the fair value hierarchy and a discussion of EME's derivative instruments, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 10. Fair Value Measurements" and " Note 2. Derivative Instruments and Hedging Activities," respectively.

Non-Trading Derivative Instruments

The fair value of outstanding non-trading commodity derivative instruments at December 31, 2009 and 2008 was $215 million and $375 million, respectively. In assessing the fair value of EME's non-trading commodity derivative 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 decrease in the fair value of commodity contracts at December 31, 2009 as compared to December 31, 2008 is attributable to the settlement of contracts in 2009 that were entered into in 2008 at higher prices than contracts outstanding at December 31, 2009. A 10% change in the market price of the underlying commodity at December 31, 2009 would increase or decrease the fair value of outstanding non-trading commodity derivative instruments by approximately $102 million. Since these non-trading commodity derivative instruments are economic hedges, an increase or decrease in fair value would be offset by an increase or decrease in the cash flows of the underlying asset. The change in the fair value of the derivative and the change in cash flows from the economically hedged item may not be recognized in operating revenues in the same periods.

Table of Contents

Energy Trading Derivative Instruments

The fair value of outstanding energy trading derivative instruments at December 31, 2009 and 2008 was $122 million and $112 million, respectively. The change in the fair value of trading contracts for the year ended December 31, 2009 was as follows:

(in millions)

Fair value of trading contracts at January 1, 2009	$	112
Net gains from energy trading activities		55
Amount realized from energy trading activities		(46)
Other changes in fair value		1
Fair value of trading contracts at December 31, 2009	$	122

A 10% change in the market price of the underlying commodity at December 31, 2009 would increase or decrease the fair value of trading contracts by approximately $1 million. The impact of changes to the various inputs used to determine the fair value of Level 3 derivatives would not be anticipated to be material to EME's results of operations as such changes would be offset by similar changes in derivatives classified within Level 3 as well as other categories.

Table of Contents

Financial Services and Other (Edison Capital and other EMG subsidiaries) Results of Operations

The following table sets forth the major changes in financial services and other net income (loss):

(in millions)	For the Years Ended December 31, 2009	2008	2007
Financial services and other operating revenue	$ 22	$ 54	$ 56
Other operation and maintenance	12	10	13
Depreciation, decommissioning and amortization	3	4	9
Lease terminations and other	887	(49)	2
Total operating expenses	902	(35)	24
Operating Income (Loss)	(880)	89	32
Interest and dividend income	11	12	16
Equity in income (loss) from partnerships and unconsolidated subsidiaries net	(11)	(3)	28
Other income	7		2
Interest expense net of amounts capitalized	(10)	(9)	(10)
Other expenses	(9)		
Income (loss) from continuing operations before income taxes	(892)	89	68
Income tax expense (benefit)	(294)	29	(2)
Income (loss) from continuing operations	(598)	60	70
Income (loss) from discontinued operations net of tax			
Net income (loss)	(598)	60	70
Less: Net income attributable to noncontrolling interests			
Financial services and other net income (loss) attributable to Edison International	$ (598)	$ 60	$ 70

Lease Termination and Other

Pursuant to the Global Settlement with the IRS, Edison Capital terminated its interests in cross-border leases during the first half of 2009 (see "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes" for further discussion). The net proceeds and loss, before income tax, from termination of the cross-border leases were $1.385 billion and $920 million, respectively. The after-tax loss on termination of the cross-border leases, including the federal and state income tax impact of the Global Settlement, was $614 million. In addition, Edison Capital sold its interest in another leverage lease transaction, Midland Cogeneration Ventures, during the second quarter of 2009 and recorded a pre-tax gain on sale of $33 million ($20 million after tax).

In March 2008, 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.

Income Tax Expense

The composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for all periods presented. The lower effective tax rate of 33% realized in 2009, as compared to the statutory rate, was primarily due to the impacts of the Global Settlement. The lower effective tax rates of 32.6% and (2.9)% realized in 2008 and 2007 respectively, as compared to the statutory rate, were primarily due to low income housing tax credits.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

At December 31, 2009, EMG and its subsidiaries had cash and equivalents and short-term investments of $808 million, excluding approximately $378 million at Edison Capital which is expected to be used to meet tax, debt and other obligations of this business segment. EMG's subsidiaries had a total of $960 million of available borrowing capacity under their credit facilities. EMG's consolidated debt at December 31, 2009 was $4.1 billion, of which $127 million was current. In addition, EME's subsidiaries had $3.2 billion of long-term lease obligations related to their sale-leaseback transactions that are due over periods ranging up to 25 years.

The following table summarizes the status of the EME and Midwest Generation credit facilities at December 31, 2009:

(in millions)	EME	Midwest Generation
Commitment	$ 600	$ 500
Less: Commitment from Lehman Brothers subsidiary	(36)	
	564	500
Outstanding borrowings		
Outstanding letters of credit	(101)	(3)
Amount available	$ 463	$ 497

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., a lender in EME's credit agreement representing a commitment of $36 million, in September 2008 declined requests for funding under that agreement and in October 2008, filed for bankruptcy protection.

EME intends to focus on a selective growth strategy, focusing primarily on the completion of renewable energy projects under construction and the development of similar projects which deploy current turbines in storage and on order. In 2010, EME anticipates capital expenditures of $1.3 billion (as described in the proceeding table) to be funded with a

Table of Contents

combination of project-level financing, U.S. Treasury grants, cash on hand, and cash flow from operations. EME intends to negotiate turbine payment deferrals, where possible. EME has secured financing of $206 million through vendor financing and anticipates funds from U.S. Treasury grants filed during the first quarter of 2010 totaling $92 million. EME intends to seek project level financing for wind projects in construction during 2010.

EME may from time to time seek to retire or purchase its outstanding debt through cash purchases and/or exchange offers, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, EME's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Redemption of Edison Capital Medium-Term Loans

In January 2010, Edison Capital redeemed in full its medium-term loans. As a result of the redemption, Edison Capital is no longer subject to the minimum net worth covenant set forth in the financial covenants.

Capital Investment Plan

The actual capital expenditures for 2009, and the currently estimated capital expenditures for 2010 through 2012 by EME's subsidiaries for existing projects, corporate activities and turbine commitments are as follows:

(in millions)	2009 Actual	2010	2011	2012
Midwest Generation Plants				
Plant capital expenditures	$ 54	$ 72	$ 79	$ 10
Environmental expenditures[1]	24	98	70	
Homer City Facilities				
Plant capital expenditures	19	31	52	24
Environmental expenditures	7	5	3	22
Renewable Projects				
Capital and construction expenditures[2]	171	746		
Turbine commitments[3,4,5]	265	357	22	
Other capital expenditures	8	20	17	9
Total	$ 548	$ 1,329	$ 243	$ 65

1 Environmental expenditures include primarily expenditures related to SNCR equipment. Additional expenditures are anticipated, however, the amounts and timing have not been determined. For additional discussion, see "Item 1. Business Environmental Matters and Regulations."

2 Includes projects beginning construction in January 2010 and $206 million in turbine purchases for 2010 where financing has been arranged. For further discussion, see "Project-Level Financing" below.

3 Turbine commitments related to the Taloga and Laredo Ridge wind projects totaling $106 million are excluded from turbine commitments and included in capital and construction expenditures in 2010. Turbine commitment figures for 2010 include amounts subject to dispute under provisions in one of the turbine supply agreements.

4 Amounts exclude balance of project costs for 302 MW available for new projects, which would be an additional $225 million to $350 million based on typical project costs.

5 One of EME's existing turbine supply agreements can be terminated for convenience. Termination of this agreement in its entirety would further reduce turbine commitments by $84 million during 2010. In the event of such termination by EME, a write-off of approximately $21 million would be recognized. Another of EME's existing turbine supply agreements can be terminated for cause or for convenience. If EME terminates the agreement, this election is likely to lead to a dispute regarding grounds for termination and/or available remedies, among other matters.

Project-Level Financing

In October 2009, EME, through its subsidiary, Big Sky, entered into turbine financing arrangements totaling approximately $206 million for wind turbine purchase obligations related to the 240 MW Big Sky wind project. For further details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 3. Liabilities and Lines of Credit."

Estimated Expenditures for Existing Projects

Plant capital expenditures relate to non-environmental projects such as upgrades to boiler and turbine controls, replacement of major boiler components, mill steam inerting projects, generator stator rewinds, 4Kv switchgear and main power transformer replacement.

Environmental expenditures at Homer City relate to emission monitoring and control projects. Midwest Generation is subject to various commitments with respect to environmental compliance. Midwest Generation continues to review all technology and unit shutdown combinations, including interim and alternative compliance solutions. For more information on the current status of environmental improvements in Illinois, see "Edison International Overview Environmental Developments" and "Item 1. Business Environmental Regulation of Edison International and Subsidiaries."

The preceding capital expenditures table includes the following projects that commenced construction or were awarded a power sales contract subsequent to December 31, 2009:

Taloga Wind Project

The Taloga wind project is a 130 MW wind project in Oklahoma scheduled for completion in late 2010. EME commenced construction activities in February 2010. EME plans to use wind turbines currently in storage to complete the Taloga wind project. The remaining costs to complete the project, including construction and turbine transportation and installation, are expected to be approximately $89 million. In January 2010, the project entered into a 20-year power purchase agreement with Oklahoma Gas and Electric Company.

Laredo Ridge Wind Project

The Laredo Ridge wind project is an 80 MW wind project in Nebraska scheduled for completion in late 2010. In February 2010, EME allocated turbines under one of its existing turbine supply agreements for 53 wind turbines to complete the Laredo Ridge wind project. The remaining costs to complete the project, including turbine payments, construction, and turbine transportation and installation, are expected to be approximately $177 million. The Laredo Ridge wind project is being developed under a joint development agreement. EME intends to purchase the project in the second quarter of 2010. The project has contracted to sell power to the Nebraska Public Power District under a 20-year power sales contract.

Table of Contents

Estimated Expenditures for Future Projects

EME had a development pipeline of potential wind projects with projected installed capacity of approximately 4,000 MW at January 31, 2010. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. EME has wind turbines in storage and on order for wind projects under construction and to be used for future wind projects (turbine commitments are reflected separately in the preceding capital expenditure table). Successful completion of development of a wind project depends upon obtaining permits and agreements necessary to support an investment and 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.

Walnut Creek Project

Walnut Creek Energy, a subsidiary of EME, was awarded by SCE, through a competitive bidding process, a 10-year power sales contract starting in 2013 for the output of a 479 MW gas-fired peaking facility located in the City of Industry, California, which is referred to as the Walnut Creek project. In July 2008, the Los Angeles Superior Court found that actions taken by the SCAQMD, in promulgating rules that had made available a "Priority Reserve" of emissions credits for new power generation projects, did not satisfy California environmental laws. In a November 2008 decision, the Los Angeles Superior Court enjoined SCAQMD from issuing Priority Reserve emission credits to Walnut Creek and other projects. Legal challenges related to the Priority Reserve emission credits are continuing. Legislation that passed the State Assembly and is currently pending in the Senate would provide access to the credits for Walnut Creek, subject to further regulatory steps and litigation risk. In the air basins regulated by SCAQMD, the need for particulate matter (PM10) and SO_2 emission credits exceeds available supply, and it is difficult to create new qualifying credits. Construction on the Walnut Creek project will not begin until its access to the Priority Reserve emission credits is restored or another source of credits is identified. The capital costs to construct this project, excluding interest, are estimated in the range of $500 million to $600 million.

Historical Consolidated Cash Flow

This section discusses EMG's consolidated cash flows from operating, financing and investing activities.

Condensed Consolidated Statement of Cash Flows

	Years Ended December 31,		
(in millions)	**2009**	**2008**	**2007**
Operating cash flow from continuing operations	$ (985)	$ 641	$ 438
Operating cash flow from discontinued operations	(7)		(2)
Net cash provided (used) by operating activities	(992)	641	436
Net cash provided (used) by financing activities	(656)	845	(603)
Net cash provided (used) by investing activities	861	(663)	(307)
Net increase (decrease) in cash and cash equivalents	$ (787)	$ 823	$ (474)

Consolidated Cash Flows (Used) by Operating Activities

The 2009 decrease in cash provided by operating activities from continuing operations was primarily attributable to:

- The impacts of the Global Settlement which resulted in net tax allocation payments to Edison International of $1.1 billion by Edison Capital related to the termination of Edison Capital's interests in cross-border leases.

- Lower realized revenues due to lower market prices in 2009, compared to 2008 and a decrease in margin deposits received from counterparties at December 31, 2009.

The 2008 increase in cash provided by operating activities from continuing operations was primarily attributable to $225 million in margin deposits received from counterparties at December 31, 2008, partially offset by the purchase of annual NO_x emission allowances in 2008 by Midwest Generation.

Consolidated Cash Flows (Used) by Financing Activities

The 2009 increase in cash used by financing activities from continuing operations was attributable to repayments of $376 million and $475 million under EME's corporate credit facility and Midwest Generation's working capital facility, respectively. These repayments were partially offset by proceeds received from the issuance of a $189 million term loan as part of a $202 million project financing completed in June 2009.

The 2008 increase in cash provided by financing activities from continuing operations was attributable to an increase in borrowings in 2008 under EME's corporate credit facility and Midwest Generation's working capital facility. In addition, EME received $12 million from the minority shareholders of the Elkhorn Ridge wind project.

Table of Contents

Consolidated Cash Flows (Used) by Investing Activities

Cash provided by investing activities was primarily due to $1.385 billion of net proceeds from termination of the cross-border leases at Edison Capital. Excluding this impact and the impact of changes in short-term investments (described below), cash provided by investing activities is related to capital expenditures and investments in other assets (primarily turbine deposits and pre-construction costs). The amount of capital expenditures and investment in other assets were $562 million in 2009, $894 million in 2008 and $838 million in 2007. The changes in the level of expenditures are primarily due to investments for renewable energy projects. Included in investments in other assets were turbine deposits for wind projects prior to the commencement of construction of $265 million in 2009, $213 million in 2008, and $271 million in 2007.

The change in short-term investments is reflected as investing activities in the cash flow statement. Investments with maturity dates less than 90 days are considered cash equivalents and are classified as part of cash and cash equivalents in the consolidated balance sheet. Maturities of short-term investments are included as a source of cash from investing activities and have decreased during the past two years primarily due to EME curtailing its purchase of short-term investments.

Other factors that impacted investing activities included:

- payments of $22 million and $19 million during 2009 and 2008, respectively, toward the purchase price of wind projects;

- proceeds of $28 million from the sale of 33% of EME's membership interest in the Elkhorn Ridge wind project during the second quarter of 2008; and

- payments of $22 million during 2007 towards the purchase price of new wind projects, payment of $24 million during 2007 to acquire an option to purchase specific projects, and payments of $11 million towards the purchase price of the Wildorado wind project during 2007.

Credit Ratings

Overview

Credit ratings for EME, Midwest Generation and EMMT are as follows:

	Moody's Rating	S&P Rating	Fitch Rating
EME[1]	B2	B	BB-
Midwest Generation[2]	Ba1	BB-	BBB-
EMMT	Not Rated	B	Not Rated

[1] Senior unsecured rating.

[2] First priority senior secured rating.

The S&P and Fitch ratings are on negative outlook, while the Moody's rating outlook is stable. EME cannot provide assurance that its current credit ratings or the credit ratings of its

Table of Contents

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

EME does not have any "rating triggers" contained in subsidiary financings that would result in it being required to make equity contributions or provide additional financial support to its subsidiaries, including EMMT. However, coal contracts at Midwest Generation include provisions that provide the right to request additional collateral to support payment obligations for delivered coal and may vary based on Midwest Generation's credit ratings. Furthermore, EMMT also has hedge contracts that do not require margin, 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. For discussions of contingent features related to energy contracts, see " Margin, Collateral Deposits and Other Credit Support for Energy Contracts."

Credit Rating of EMMT

The Homer City sale-leaseback documents restrict Homer City's ability to enter into derivative 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 also include a requirement that Homer City's counterparty to such transactions, whether it is EMMT or another party, and 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 Homer City is not rated. In order to continue to sell forward the output of the Homer City facilities through EMMT, EME has obtained a consent from the sale-leaseback owner participants that allows Homer City to enter into such sales, under specified conditions, through March 1, 2014. Homer City continues to be in compliance with the terms of the consent; however, because EMMT's credit rating has dropped below BB-, the consent is revocable by the sale-leaseback owner participants at any time. The sale-leaseback owner participants have not indicated that they intend to revoke the consent; however, there can be no assurance that they will not do so in the future. An additional consequence of EMMT's lowered credit rating is that outstanding accounts receivable between EMMT and Homer City have been reduced to zero, as required under the terms of the consent. Revocation of the consent would not affect trades between EMMT and Homer City that had been entered into while the consent was still in effect. EME is permitted to sell the output of the Homer City facilities into the spot market on the terms set forth in the Homer City sale-leaseback documents. For further discussion, see "EMG: Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Fossil-Fueled 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 price exposure through EMMT. 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, 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 December 31, 2009, EMMT had deposited $85 million in cash with clearing brokers in support of futures contracts and had deposited $35 million in cash with counterparties in support of forward energy and congestion contracts. Cash collateral provided to others offset against derivative liabilities totaled $49 million at December 31, 2009. In addition, EME had received cash collateral of $124 million at December 31, 2009, to support credit risk of counterparties under margin agreements; $68 million of which is classified as restricted cash. The liability for margin deposits received from counterparties has been offset against net derivative assets.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2009, if wholesale energy prices change or additional transactions are entered into. EME estimates that margin and collateral requirements for energy and congestion contracts outstanding as of December 31, 2009 could increase by approximately $90 million over the remaining life of the contracts using a 95% confidence level. This increase may not be offset by similar changes in the cash flows of the underlying hedged items in the same periods. Certain EMMT hedge contracts do not require margin, 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 " Dividend Restrictions 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. EMMT also has hedge contracts that do not require margin, 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 all derivative instruments with credit-risk-related contingent features is in an asset position on December 31, 2009 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 additional collateral postings under the contingent features described above.

Midwest Generation has cash on hand and a credit facility to support margin requirements specifically related to contracts entered into by EMMT related to the Midwest Generation plants. In addition, EME has cash on hand and a credit facility to provide credit support to subsidiaries. For discussion on available borrowing capacity under Midwest Generation and EME credit facilities, see "EMG: Liquidity and Capital Resources Overview."

Intercompany Tax-Allocation Agreement

EME and Edison Capital are included in the consolidated federal and combined state income tax returns of Edison International and are eligible to participate in tax-allocation payments with other subsidiaries of Edison International in circumstances where domestic tax losses are incurred. The right of EME and Edison Capital to receive and the amount of and timing of tax-allocation payments are dependent on the inclusion of EME and Edison Capital in the consolidated income tax returns of Edison International and its subsidiaries and other factors, including the consolidated taxable income of Edison International and its subsidiaries, the amount of net operating losses and other tax items of EMG's subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. EME and Edison Capital receive tax-allocation payments for tax losses when and to the extent that the consolidated Edison International group generates sufficient taxable income in order to be able to utilize EME's or Edison Capital's consolidated tax losses in the consolidated income tax returns for Edison International and its subsidiaries. Based on the application of the factors cited above, EME and Edison Capital are obligated during periods it generates taxable income to make payments under the tax-allocation agreements. In connection with the Global Settlement with the IRS, EME made a payment of $18 million and assigned a tax receivable of $125 million to its parent, Mission Energy Holding Company, in satisfaction of its obligations under a tax-allocation agreement in the second quarter of 2009. In addition, EME received net tax-allocation payments of $166 million in 2009 and made net tax-allocation payments to Edison International of $95 million and $112 million in 2008 and 2007, respectively. In connection with the Global Settlement, Edison Capital made net tax-allocation payments of $1.1 billion in 2009. Edison Capital made net tax-allocation payments of $15 million in 2008 and received net tax-allocation payments from Edison International of $17 million in 2007.

Debt Covenants and Dividend Restrictions

Credit Facility Financial Ratios

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 following table sets forth the interest coverage ratio for the 12 months ended December 31, 2009 and 2008:

	Years Ended December 31,	
	2009	**2008**
Ratio	1.72	1.98
Covenant threshold (not less than)	1.20	1.20

The following table sets forth the corporate-debt-to-corporate-capital ratio at December 31, 2009 and 2008:

	December 31,	
	2009	**2008**
Corporate-debt-to-corporate-capital ratio	0.54	0.60
Covenant threshold (not more than)	0.75	0.75

Table of Contents

Dividend Restrictions in Major Financings

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

Key Ratios of EME's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME's principal subsidiaries required by financing arrangements at December 31, 2009 or for the 12 months ended December 31, 2009:

Subsidiary	**Financial Ratio**	**Covenant**	**Actual**
Midwest Generation (Midwest Generation plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.18 to 1
Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.96 to 1

Midwest Generation Financing Restrictions on Distributions

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

Homer City

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

At the end of each quarter, the senior rent service coverage ratio for the prior 12-month period (taken as a whole) must be greater than 1.7 to 1. The senior rent service coverage ratio is defined as all income and receipts of Homer City less amounts paid for operating expenses, capital expenditures funded by Homer City, taxes and financing fees divided by the aggregate amount of the debt portion of the rent, plus fees, expenses and indemnities due and payable with respect to the lessor's debt service reserve letter of credit.

Table of Contents

At the end of each quarter, the equity and debt portions of rent then due and payable must have been paid. The senior rent service coverage ratio (discussed above) projected for each of the prospective two 12-month periods must be greater than 1.7 to 1. No more than two rent default events may have occurred, whether or not cured. A rent default event is defined as the failure to pay the equity portion of the rent within five business days of when it is due. EME has not guaranteed Homer City's obligations under the leases.

Corporate Credit Facility Restrictions on Distributions from Subsidiaries

EME's corporate credit agreement contains covenants that restrict its ability and the ability of several of its subsidiaries to make distributions. This restriction impacts the subsidiaries that own interests in the Westside projects, the Sunrise project, the fossil-fueled facilities, and the Big 4 projects. These subsidiaries would not be able to make a distribution to EME's shareholder if an event of default were to occur and be continuing under EME's secured credit agreement after giving effect to the distribution.

Senior Notes and Guaranty of Powerton-Joliet Leases

EME is restricted from the sale or disposition of assets, which includes the making of a distribution, if the aggregate net book value of all such sales and dispositions during the most recent 12-month period would exceed 10% of consolidated net tangible assets as defined in such agreements computed as of the end of the most recent fiscal quarter preceding such sale or disposition. At December 31, 2009, the maximum sale or disposition of EME assets was $799 million.

Table of Contents

Contractual Obligations, Commercial Commitments and Contingencies

Contractual Obligations

EME has contractual obligations and other commercial commitments that represent prospective cash requirements. The following table summarizes EME's significant consolidated contractual obligations as of December 31, 2009.

(in millions)	Total	Less than 1 year	Payments Due by Period 1 to 3 years	3 to 5 years	More than 5 years
Long-term debt[1]	$ 6,481	$ 322	$ 640	$ 1,088	$ 4,431
Operating lease obligations[2]	3,448	353	665	627	1,803
Purchase obligations[3]:					
Capital improvements	441	441			
Turbine commitments	485	463	22		
Fuel supply contracts	932	457	475		
Gas transportation agreements	68	8	16	17	27
Coal transportation	388	244	144		
Other contractual obligations	236	84	127	25	
Employee benefit plan contribution[4]	24	24			
Total Contractual Obligations[5,6]	$ 12,503	$ 2,396	$ 2,089	$ 1,757	$ 6,261

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 3. Liabilities and Lines of Credit." Amount also includes interest payments totaling $2.5 billion over applicable period of the debt.

2 At December 31, 2009, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet Stations and the Homer City facilities. For further discussion, see " Off-Balance Sheet Transactions Sale-Leaseback Transactions" and "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

3 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

4 Amount includes estimated contribution for pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2010 are not available. For more information, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Compensation and Benefit Plans Pension Plans and Postretirement Benefits Other than Pensions."

5 At December 31, 2009, EME had a total net liability recorded for uncertain tax positions of $97 million, which is excluded from the table. EME cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the Internal Revenue Service. For more information, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes."

6 The contractual obligations table does not include derivative obligations and AROs, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Derivative Instruments and Hedging Activities," and " Note 8. Property and Plant," respectively.

Table of Contents

Commercial Commitments

Standby Letters of Credit

As of December 31, 2009, standby letters of credit under EME and its subsidiaries' credit facilities aggregated $119 million and were scheduled to expire as follows: $111 million in 2010 and $8 million in 2011.

Contingencies

EME's significant contingencies related to the Midwest Generation NSR lawsuit and the Homer City NSR NOV, environmental remediation, and environmental developments are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

Off-Balance Sheet Transactions

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

Investments Accounted for under the Equity Method

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

EME owns a number of domestic energy projects through partnerships in which it has a 50% or less ownership interest. Entities formed to own these projects are generally structured with a management committee in which EME exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. Two of these projects have long-term debt that is secured by a pledge of the assets of the project entity, but do not provide for any recourse to EME. Accordingly, a default on a long-term financing of a project could result in foreclosure on the assets of the project entity resulting in a loss of some or all of EME's project investment, but would not require EME to contribute additional capital. At December 31, 2009, entities which EME has accounted for under the equity method had indebtedness of $245 million, of which $104 million is proportionate to EME's ownership interest in these projects.

Edison Capital has invested in affordable housing projects utilizing partnership or limited liability companies in which Edison Capital is a limited partner or limited liability member. In these entities, Edison Capital usually owns a 99% interest. With a few exceptions, an unrelated general partner or managing member exercises operating control; voting rights of Edison Capital are limited by agreement to certain significant organizational matters. Edison Capital has subsequently sold a majority of these interests to unrelated third party investors through syndication partnerships in which Edison Capital has retained an interest, with one exception, of less than 20%. The debt of those partnerships and limited liability companies is secured by real property. At December 31, 2009, entities that Edison Capital has accounted for under the equity method had indebtedness of approximately $1.5 billion, of which approximately $631 million is proportionate to Edison Capital's ownership interest in these projects. Substantially all of this debt is nonrecourse to Edison Capital.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Powerton Station and Units 7 and 8 of the Joliet Station in Illinois and the Homer City facilities in Pennsylvania. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies Lease Commitments."

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

Power Station(s)	Acquisition Price	Equity Investor	Original Equity Investment in Owner/Lessor (in millions)	Amount of Lessor Debt at December 31, 2009		Maturity Date of Lessor Debt
Powerton/Joliet	$ 1,367	PSEG/Citigroup, Inc.	$ 238	$	Series A	2009
				679	Series B	2016
Homer City	1,591	GECC/ Metropolitan Life Insurance Company	798	$ 219	Series A	2019
				506	Series B	2026

PSEG PSEG Resources, Inc.
GECC General Electric Capital Corporation

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

Leveraged Leases

Edison Capital is a lessor in power and infrastructure projects with terms of 25 to 30 years. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 18. Investments in Leveraged Leases, Partnerships and Unconsolidated Subsidiaries" for details of the lease investments.

Table of Contents

MARKET RISK EXPOSURES

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 the prices of electricity, capacity, fuel, 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 instruments in accordance with established policies and procedures.

Commodity Price Risk

EME's merchant operations create exposure to commodity price risk, which reflects the potential impact of a change in the market value of a particular commodity. Commodity price risks are actively monitored, with oversight provided 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 may vary.

EME uses estimates of the variability in gross margin to help identify, measure, monitor and control its overall market risk exposure and earnings volatility with respect to hedge positions at the fossil-fueled facilities, and the merchant wind projects, and uses "value at risk" metrics to help identify, measure, monitor and control its overall risk exposure with respect to its trading positions. These measures allow management to aggregate overall commodity risk, compare risk on a consistent basis and identify changes in risk factors. Value at risk measures the possible loss, and variability in gross margin 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 volumetric exposure limits.

Energy Price Risk Affecting Sales from the Fossil-Fueled Facilities

Energy and capacity from the fossil-fueled facilities are sold under terms, including price, duration 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. Power is sold into PJM at spot prices based upon locational marginal pricing. Hedging transactions related to generation are generally entered into at the Northern Illinois Hub or the AEP/Dayton Hub, both in PJM, for the Midwest Generation plants and generally

Table of Contents

at the PJM West Hub for the Homer City facilities. These trading hubs have been the most liquid locations for hedging purposes. See " Basis Risk" below for further discussion.

The following table depicts the average historical market prices for energy per megawatt-hour at the locations indicated:

	24-Hour Average Historical Market Prices[1]		
	2009	**2008**	**2007**
Midwest Generation plants			
Northern Illinois Hub	$ 28.86	$ 49.01	$ 45.53
Homer City facilities			
PJM West Hub	$ 38.31	68.56	59.87
Homer City Busbar	34.91	57.72	51.03

1 Energy prices were calculated at the respective delivery points using historical hourly real-time prices as published by PJM or provided on the PJM web-site.

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the Northern Illinois Hub and PJM West Hub at December 31, 2009:

	24-Hour Forward Energy Prices[1]	
	Northern Illinois Hub	**PJM West Hub**
2010 calendar "strip"[2]	$ 33.87	$ 48.04
2011 calendar "strip"[2]	$ 34.73	$ 49.43

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

2 Market price for energy purchases for the entire calendar year.

Forward market prices at the Northern Illinois Hub and 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 fossil-fueled facilities into these markets may vary materially from the forward market prices set forth in the preceding table.

Table of Contents

EMMT engages in hedging activities for the fossil-fueled facilities to hedge the risk of future change in the price of electricity. The following table summarizes the hedge positions as of December 31, 2009 for electricity expected to be generated in 2010 and 2011:

	2010		2011	
	MWh (in thousands)	Average price/ MWh[1]	MWh (in thousands)	Average price/ MWh[1]
Midwest Generation plants				
Northern Illinois and AEP/Dayton Hubs	19,717	$ 42.66	1,428	$ 59.64
Homer City facilities				
PJM West Hub	3,673	79.25	29	54.47
Total	23,390		1,457	

1 The above hedge positions 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 are not directly comparable to the 24-hour Northern Illinois Hub or PJM West Hub prices set forth above. Furthermore, the average price/MWh for Homer City's hedge position is based on the PJM West Hub. Energy prices at the Homer City busbar have been lower than energy prices at the PJM West Hub.

In addition, as of December 31, 2009, EMMT has entered into 3.3 billion cubic feet of natural gas futures contracts (equivalent to approximately 557 GWh of energy only contracts using a ratio of 6 MMBtu to 1 MWh) for the Midwest Generation plants to economically hedge energy price risks during 2010 at an average price of $38.40/MWh.

Capacity Price Risk

On June 1, 2007, PJM implemented the RPM for capacity. Under the RPM, capacity commitments are made in advance to provide a long-term pricing signal for capacity resources. The RPM is intended to provide a mechanism for PJM to meet the region's need for generation capacity, while allocating the cost to load-serving entities through a locational reliability charge.

Table of Contents

The following table summarizes the status of capacity sales for Midwest Generation and Homer City at December 31, 2009:

	Installed Capacity	Unsold Capacity[1]	Capacity Sold	RPM Capacity Sold in Base Residual Auction		Other Capacity Sales, Net of Purchases[2]		Aggregate Average Price per
	MW	MW	MW	MW	Price per MW-day	MW	Average Price per MW-day	MW-day
January 1, 2010 to May 31, 2010								
Midwest Generation	5,776	(878)	4,898	5,329	$ 102.04	(431)	$ 99.23	$ 102.29
Homer City	1,884	(206)	1,678	1,670	191.32	8	191.32	191.32
June 1, 2010 to May 31, 2011								
Midwest Generation	5,477	(548)	4,929	4,929	$ 174.29			174.29
Homer City	1,884	(71)	1,813	1,813	174.29			174.29
June 1, 2011 to May 31, 2012								
Midwest Generation	5,477	(495)	4,982	4,582	$ 110.00	400	85.00	107.99
Homer City	1,884	(113)	1,771	1,771	110.00			110.00
June 1, 2012 to May 31, 2013								
Midwest Generation	5,477	(773)	4,704	4,704	$ 16.46			16.46
Homer City	1,884	(148)	1,736	1,736	133.37			133.37

1 Capacity not sold arises from: (i) capacity retained to meet forced outages under the RPM auction guidelines, and (ii) capacity that PJM does not purchase at the clearing price resulting from the RPM auction.

2 Other capacity sales and purchases, net includes contracts executed in advance of the RPM base residual auction to hedge the price risk related to such auction, participation in RPM incremental auctions and other capacity transactions entered into to manage capacity risks.

The RPM auction capacity prices for the delivery period of June 1, 2012 to May 31, 2013 varied between different areas of PJM. In the western portion of PJM, affecting Midwest Generation, the price of $16.46 per MW-day was substantially lower than previous capacity prices. The decrease in forward capacity prices was attributable to a substantial increase in demand side management resources. The impact of lower capacity prices for this period will have an adverse effect on Midwest Generation's revenues unless such lower capacity prices are offset by an unavailability of competing resources and increased energy prices, which is uncertain.

Revenues from the sale of capacity from Midwest Generation and 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, demand side management activities and the cost of new entry.

Table of Contents

Basis Risk

Sales made from the fossil-fueled 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 Midwest Generation plants. EME's hedging activities use these settlement points (and, to a lesser extent, other similar trading hubs) to enter into hedging contracts. 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 2009, 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 9%, compared to 16% during 2008 and 15% during 2007. During 2009, transmission congestion in PJM has resulted in prices at the individual busbars of the Midwest Generation plants being lower than those at the AEP/Dayton Hub and Northern Illinois Hub by an average of 14% and less than 1%, respectively, compared to 10% and 2%, respectively, during 2008.

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 Homer City and Midwest Generation. A financial transmission right is a financial instrument that entitles the holder to receive the difference between 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 Midwest Generation plants and Homer City facilities purchase coal primarily obtained from the Southern PRB of Wyoming and from mines located near the facilities in Pennsylvania, respectively.

Table of Contents

Coal purchases are made under a variety of supply agreements. The following table summarizes the amount of coal under contract at December 31, 2009 for the following three years:

	Amount of Coal Under Contract in Millions of Equivalent Tons[1]		
	2010	**2011**	**2012**
Midwest Generation plants[2]	17.3	9.8	9.8
Homer City facilities[3]	4.6	2.3	1.2

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

2 In January and February 2010, Midwest Generation entered into additional contractual agreements for the purchase of 1 million tons for 2010 and 2 million tons for 2011.

3 In January 2010, Homer City exercised options under existing contractual agreements for the purchase of 0.3 million tons for 2011, 0.5 million tons for 2012 and 0.5 million tons for 2013. In February 2010, Homer City entered into additional contractual agreements for the purchase of 0.4 million tons for 2011.

EME is subject to price risk for purchases of coal that are not under contract. Prices of NAPP coal, which are related to the price of coal purchased for the Homer City facilities, decreased during 2009 from 2008 and increased substantially during 2008 from 2007. The price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content) decreased to a price of $52.50 per ton at December 31, 2009, compared to a price of $76 per ton at January 9, 2009, as reported by the EIA. In 2009, the price of NAPP coal ranged from $43.50 per ton to $76 per ton, as reported by the EIA. The 2009 decrease in NAPP coal prices was due in part to current global economic conditions that have lessened demand for coal, high levels of inventories and fuel switching. In 2008, the price of NAPP coal ranged from $61.75 per ton to $150 per ton, as reported by the EIA. In 2007, the price of NAPP coal fluctuated between $44.00 per ton to $55.25 per ton, which was the price per ton at December 21, 2007, as reported by the EIA.

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 Midwest Generation plants declined during 2009 from 2008 year-end prices and increased during 2008 from 2007 year-end prices. The price of PRB coal fluctuated between $8.25 per ton and $13 per ton during 2009, with a price of $9.25 per ton at December 31, 2009, as reported by the EIA. The 2009 decrease in PRB coal prices was due to lower demand and higher levels of inventory. In 2008, the price of PRB coal fluctuated between $11 per ton to $14.50 per ton, with a price of $13 per ton at January 9, 2009, as reported by the EIA. In 2007, the price of PRB coal ranged from $8.35 per ton to $11.50 per ton, which was the price per ton at December 21, 2007, as reported by the EIA.

EME has contractual agreements for the transport of coal to its facilities. The primary contract is with Union Pacific Railroad (and various short-haul 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

Table of Contents

are higher than the existing rates under contract (transportation costs are approximately half of the delivered cost of PRB coal to the Midwest Generation plants).

Based on EME's anticipated coal requirements in 2010 in excess of the amount under contract, EME expects that a 10% change in the price of coal at December 31, 2009 would increase or decrease pre-tax income in 2010 by approximately $6 million.

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO_2 allowances sufficient to cover their annual emissions. Pursuant to Pennsylvania's and Illinois' implementation of the CAIR, electric generating stations also are required to hold seasonal and annual NO_x allowances beginning January 1, 2009. As part of the acquisition of the fossil-fueled facilities, EME obtained emission allowance rights 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. For further discussion of the CAIR, see "Item 1. Business Environmental Matters and Regulations Air Quality Nitrogen Oxide and Sulfur Dioxide."

In the event that actual emissions required are greater than allowances held, EME is subject to price risk for purchases of emission allowances. The market price for emission allowances may vary significantly. The average purchase price of SO_2 allowances was $65 per ton in 2009, $315 per ton in 2008 and $512 per ton in 2007. The average purchase price of annual NO_x allowances was $1,431 per ton in 2009. Based on broker's quotes and information from public sources, the spot price for SO_2 allowances and annual NO_x allowances was $60 per ton and $665 per ton, respectively, at December 31, 2009.

Based on EME's anticipated annual and seasonal NO_x requirements for 2010 beyond those allowances already purchased, EME expects that a 10% change in the price of annual and seasonal NO_x emission allowances at December 31, 2009 would increase or decrease pre-tax income in 2010 by approximately $0.7 million.

Credit Risk

In conducting EME's hedging and trading activities, EME enters into transactions with 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 market price changes occurring since the original contract was executed if the nonperforming counterparty were unable to pay the resulting damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time a counterparty defaulted.

To manage credit risk, EME evaluates the risk of potential defaults by counterparties. Credit risk is measured as the loss that EME would expect to incur if a counterparty failed to perform pursuant to the terms of its 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.

EME has established processes to determine and monitor the creditworthiness of counterparties. EME manages the credit risk of its counterparties based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. A risk management committee regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

The credit risk exposure from counterparties of merchant energy 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 December 31, 2009, the balance sheet exposure as described above, broken down by the credit ratings of EME's counterparties, was as follows:

	December 31, 2009		
(in millions)	**Exposure[2]**	**Collateral**	**Net Exposure**
Credit Rating[1]			
A or higher	$ 267	$ (102)	$ 165
A-	53		53
BBB+	54		54
BBB	57		57
BBB-	35		35
Below investment grade	12	(12)	
Total	$ 478	$ (114)	$ 364

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 $160 million of net accounts receivable and payables and $318 million representing the fair value of derivative contracts. The exposure is based on master netting agreements with the related counterparties. Due to developments in the financial markets, credit ratings may not be reflective of the actual related credit risks. In addition to the amounts set forth in the above table, EME's subsidiaries have posted a $120 million cash margin in the aggregate with PJM, NYISO, MISO, clearing brokers and other counterparties to support hedging and trading activities. The margin posted to support these activities also exposes EME to credit risk of the related entities.

Table of Contents

The majority of EME's consolidated wind projects and unconsolidated affiliates that own power plants sell power under power purchase agreements. Generally, each project or plant sells its output to one counterparty. A default by the counterparty, including a default as a result of a bankruptcy, would likely have a material adverse effect on the operations of the project or plant.

Coal for the fossil-fueled facilities is purchased from suppliers under contracts which may be for multiple years. A number of the coal suppliers to the fossil-fueled 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.

The fossil-fueled facilities sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transact in capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 48% of EME's consolidated operating revenues for the year ended December 31, 2009. 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. Losses resulting from a PJM member default are shared by all other members using a predetermined formula. At December 31, 2009, EME's account receivable due from PJM was $50 million.

For the year ended December 31, 2009, a second customer, Constellation Energy Commodities Group, Inc., accounted for 16% of EME's consolidated operating revenues. Sales to Constellation are primarily generated from the fossil-fueled facilities and consist of energy sales under forward contracts. The contract with Constellation is guaranteed by Constellation Energy Group, Inc., which at December 31, 2009 had a senior unsecured debt rating of BBB- by S&P and Baa3 by Moody's. At December 31, 2009, EME's account receivable due from Constellation was $36 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 agreements. EME's 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 EME's turbine suppliers may have a material impact on EME's wind projects and development efforts.

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 $3.25 billion at December 31, 2009, compared to the carrying value of $4.1 billion. A 10% increase in market interest rates at December 31, 2009 would result in a decrease in the fair value of total long-term obligations by approximately $176 million. A 10% decrease in market interest rates at December 31, 2009 would result in an increase in the fair value of total long-term obligations by approximately $194 million.

EDISON INTERNATIONAL PARENT AND OTHER

RESULTS OF OPERATIONS

Results of operations for Edison International parent and other includes amounts from other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

Edison International parent and other earnings (loss) from continuing operations were $18 million, $(29) million and $(19) million for 2009, 2008 and 2007, respectively. The increase in 2009 was due to the impact of the Global Settlement resulting from lower combined state deferred income taxes recorded by Edison International and its subsidiaries under their respective tax allocation agreements.

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flow

This section discusses Edison International (parent) and other cash flows from operating, financing and investing activities.

Condensed Statement of Cash Flows

(in millions)	**2009**	**2008**	**2007**
Cash flows used by operating activities	$ (32)	$ (3)	$ (165)
Cash flows provided (used) by financing activities	(273)	290	114
Net cash provided (used) by investing activities	(2)	6	3
Net increase (decrease) in cash and equivalents	$ (307)	$ 293	$ (48)

Cash Flows Used by Operating Activities

Cash flows from operating activities were primarily related to interest, operating costs and income taxes of Edison International (parent). Included in operating activities during 2009 was the impacts of the Global Settlement which resulted in remittances of approximately $343 million to the IRS and the Franchise Tax Board.

Under the tax allocation agreement with EMG, Edison International received net payments of approximately $1.2 billion, principally from Edison Capital funded by the proceeds of termination of the cross border leases. Edison International made net tax allocation payments of approximately $875 million to SCE.

Table of Contents

Edison International expects that the Global Settlement, together with the termination of the Edison Capital cross border leases, will result in a positive cash impact over time. The following table provides the approximate cash flow expected over time by major subsidiary:

(in millions)	SCE	Edison Capital	Edison International (parent), EME, and All Other[1]	Edison International Consolidated
Net proceeds from termination of cross-border leases	$	$ 1,385	$	$ 1,385
Taxes settled through December 31, 2009	875	(1,069)	(149)	(343)
Estimated future net tax (payments) receipts	(229)	(602)	189	(642)
Cash flow expected over time	$ 646	$ (286)	$ 40	$ 400

1 Includes all other Edison International consolidated subsidiaries including EME and other EMG subsidiaries.

See "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes" for further discussion of the Global Settlement.

The $162 million increase in 2008 cash flows from operating activities compared to 2007 was primarily due to the following:

SCE held $78 million and $75 million of intercompany notes receivables from EME and Edison International, respectively, which were repaid in 2007. The elimination of the cash received to settle the intercompany receivable is reflected in cash flows from operating activities, and the elimination of EME's repayment of its intercompany note payable is reflected in financing activities.

Cash Flows Provided (Used) by Financing Activities

Financing activities for 2009 were as follows:

Paid $404 million of (or $0.31 per share) dividends to Edison International common shareholders. These quarterly dividends represent an increase of $0.005 per share over quarterly dividends paid in 2008.

In December 2009, the Board of Directors of Edison International declared a $0.315 per share quarterly dividend which was paid in January 2010. This quarterly dividend represents an increase of $0.005 per share over quarterly dividends paid in 2009. The 2009 dividend increase is consistent with Edison International's dividend policy of paying out approximately 45% to 55% of the earnings of SCE and balancing dividend increases with the significantly growing capital needs of Edison International's business.

Repaid a net $165 million of short-term debt, primarily due to the improvement in economic conditions that occurred during the second half of 2008.

Received $300 million of dividend payments from SCE.

Table of Contents

Financing activities for 2008 were as follows:

- Paid $397 million of dividends to Edison International common shareholders.
- Received $325 million of dividend payments from SCE.
- Issued $250 million of short-term debt, primarily due to the economic conditions that occurred during the second half of 2008.
- Received $120 million from an intercompany loan between Edison Capital and Edison International in 2008.

Financing activities for 2007 were as follows:

- Paid $378 million of dividends to Edison International common shareholders.
- Repaid $75 million of intercompany notes payable to SCE (discussed above in operating activities).
- Received $135 million and $237 million of dividend payments from SCE and EME, respectively.
- Received $50 million from an intercompany loan between Edison Capital and Edison International in 2007.

EDISON INTERNATIONAL (CONSOLIDATED)

Contractual Obligations

Edison International's contractual obligations as of December 31, 2009, for the years 2010 through 2014 and thereafter are estimated below.

(in millions)	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt maturities and interest[1]	$ 20,092	$ 1,017	$ 1,347	$ 2,809	$ 14,919
Operating lease obligations[2]	15,524	1,132	2,215	2,184	9,993
Capital lease obligations[3]	235	8	11	13	203
Purchase obligations[4]:					
Capital improvements	441	441			
Turbine commitments	485	463	22		
Fuel supply contracts	2,316	637	797	291	591
Purchased-power capacity payments	6,837	395	1,024	1,384	4,034
Gas and coal transportation payments	456	252	160	17	27
Other contractual obligations	281	89	139	39	14
Employee benefit plans contributions[5]	153	153			
Total[6, 7]	$ 46,820	$ 4,587	5,715	6,737	29,781

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 3. Liabilities and Lines of Credit." Amount includes interest payments totaling $9.5 billion over applicable period of the debt.

2 At December 31, 2009, minimum operating lease payments were primarily related to power contracts, vehicles, office space and other equipment. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

Table of Contents

3
At December 31, 2009, minimum capital lease payments were primarily related to power purchased contracts that meet the requirements for capital leases. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

4
For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

5
Amount includes estimated contributions to the pension and PBOP plans. The estimated contributions for Edison International are not available beyond 2010. Due to the volatile market conditions experienced in 2008 and the decline in value of Edison International's trusts, Edison International's contributions increased in 2009. Based on pension and PBOP plan assets at December 31, 2009, SCE expects a decrease in contributions in 2010 but cannot predict or estimate contributions beyond 2010. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Compensation and Benefit Plans" for further information.

6
At December 31, 2009, Edison International had a total net liability recorded for uncertain tax positions of $621 million, which is excluded from the table. Edison International cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the IRS.

7
The contractual obligations table does not include derivative obligations and asset retirement obligations, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Derivative Instruments and Hedging Activities," and "Item 8. Edison International Notes to Consolidated Financial Statements Note 8. Property and Plant," respectively.

Critical Accounting Estimates and Policies

The accounting policies described below are considered critical to obtaining an understanding of Edison International's consolidated financial statements because their application requires the use of significant estimates and judgments by management in preparing the consolidated financial statements. Management estimates and judgments are inherently uncertain and may differ significantly from actual results achieved. Management considers an accounting estimate to be critical if the estimate requires significant assumptions and changes in the estimate or, the use of alternative estimates, that could have a material impact on Edison International's results of operations or financial position. For more information on Edison International's accounting policies, see "Item 8. Edison International's Notes to Consolidated Financial Statements Note 1. Summary of Significant Accounting Policies."

Rate Regulated Enterprises

Nature of Estimate Required. SCE follows the accounting principles for rate-regulated enterprises which are required for entities whose rates are set by regulators at levels intended to recover the estimated costs of providing service, plus a return on net investment, or rate base. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow a cost that would otherwise be charged as an expense by a unregulated entity to be capitalized as a regulatory asset if it is probable that such cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred.

Key Assumptions and Approach Used. SCE's management assesses at the end of each reporting period whether regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific or a similar incurred cost to SCE or other rate-regulated entities in California, and other factors that would indicate that the regulator will treat an incurred cost as allowable for rate-making purposes. Using these factors, management has determined that existing regulatory assets and liabilities are probable of future recovery or settlement. This determination reflects the current regulatory climate in California and is subject to change in the future.

Effect if Different Assumption Used. Significant management judgment is required to evaluate the anticipated recovery of regulatory assets, the recognition of incentives and revenue subject to refund, as well as the anticipated cost of regulatory liabilities or penalties. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2009, the consolidated balance sheets included regulatory assets of $4.3 billion and regulatory liabilities of $3.7 billion. If different judgments were reached on recovery of costs and timing of income recognition, SCE's earnings and cash flows may vary from the amounts reported.

Derivatives

Nature of Estimates Required. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment. Certain of Edison International's long-term power sales and fuel supply agreements related to its generation activities either: (1) do not meet the definition of a derivative, or (2) qualify as normal purchases and sales and are, therefore, recorded on an accrual basis. SCE's fair value changes are expected to be recovered from or refunded to ratepayers, and therefore SCE's fair value changes have no impact on earnings, but may temporarily affect cash flows. SCE has elected not to use hedge accounting for these transactions due to this regulatory accounting treatment.

EME uses derivative instruments for hedging activities and trading purposes. Derivative instruments are mainly utilized by EME to manage exposure to changes in electricity and fuel prices and interest rates. Derivative commodity instruments include forward sales transactions entered into on a bilateral basis with third parties, futures contracts, full requirements services contracts or load requirements services contracts, and capacity transactions. Financial derivative instruments include interest rate swaps entered into on a bilateral basis with counterparties. EME follows authoritative guidance on derivatives and hedging, which requires derivative instruments to be recorded at fair value unless an exception applies. Authoritative guidance also requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for hedge accounting, depending on the nature of the hedge, changes in fair value are either offset by changes in the fair value of the hedged assets, liabilities or firm commitments through earnings, or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of a derivative's change in fair value is immediately recognized in earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

EME records derivative instruments used for trading utilizing the fair value model. EME's derivative instruments with a short-term duration (less than one year) are normally valued

Table of Contents

using quoted market prices. In the absence of quoted market prices, derivative instruments with a short-term duration are valued considering the time value of money, volatility of the underlying commodity, and other factors as determined by EME. Resulting gains and losses are recognized in operating revenues on the accompanying consolidated income statements.

Derivative assets include open derivative positions recorded at fair value, including cash flow hedges, that are "in-the-money" and the present value of net amounts receivable from structured transactions. Derivative liabilities include open derivative positions, including cash flow hedges, that are "out-of-the-money." Where EME enters into master agreements and other arrangements in conducting hedging and trading activities with a right of setoff in the event of bankruptcy or default by the counterparty, these types of transactions are reported net on the balance sheet.

Key Assumptions and Approach Used. EME determines the fair value of its derivatives based on forward market prices in active markets adjusted for nonperformance risk. If quoted market prices are not available, internally developed models are used to determine the fair value. When actual market prices, or relevant observable inputs are not available, it is 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. In assessing nonperformance 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 nonperformance.

In addition, a fair value hierarchy is established that prioritizes the inputs to valuation techniques used to measure fair value. For further information, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 10. Fair Value Measurements."

Effect if Different Assumptions Used. As described above, fair value is determined using a combination of market information or observable data and unobservable inputs which reflect management's assumptions. Changes in observable data would impact results. In addition, unobservable inputs could have an impact on results. Fair value for Level 3 derivatives is derived using observable and unobservable inputs. As of December 31, 2009, EME and SCE Level 3 derivatives had a net fair value of $173 million and $(111) million, respectively. While it is difficult to determine the impact of a change in any one input, if the fair value of EME and SCE Level 3 derivatives were increased or decreased by 10%, the impact would be a $17 million and $11 million increase or decrease to operating revenues, respectively.

For Edison International's derivative instruments that are measured at fair value using quantitative pricing models, a significant change in estimate could affect Edison International's results of operations. For further sensitivities in Edison International's assumptions used to calculate fair value, see " EMG: Results of Operations Fair Value Measurements" and " SCE: Market Risk Exposures Natural Gas and Electricity Price Risk." For further information on derivative instruments, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Derivative Instruments and Hedging Activities."

Nuclear Decommissioning ARO

Nature of Estimate Required. Regulations by the NRC require SCE to decommission its nuclear power plants which is expected to begin after the plants' operating licenses expire. In accordance with authoritative guidance, SCE is required to record an obligation to decommission its nuclear facilities. Nuclear decommissioning costs are recovered in utility rates through contributions that are reviewed every three years by the CPUC. Due to regulatory accounting treatment, nuclear decommissioning activities are not expected to affect SCE earnings.

Key Assumptions and Approach Used. The liability to decommission SCE's nuclear power facilities is based on site-specific studies performed in 2005 which estimate that SCE will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. Decommissioning cost estimates are updated in each Nuclear Decommissioning Triennial Proceeding. A site-specific study was performed in 2008 which is currently awaiting CPUC approval. Once a CPUC decision is rendered the updated cost estimate is established and accreted over the lives of San Onofre and Palo Verde. The current estimate is based on the following assumptions from the 2005 site-specific study:

Decommissioning Costs. The estimated costs for labor, dismantling and disposal costs, energy and miscellaneous costs.

Escalation Rates. Annual escalation rates are used to convert the decommissioning cost estimates in base year dollars to decommissioning cost estimates in future-year dollars. Escalation rates are primarily used for labor, material, equipment, and low level radioactive waste burial costs. SCE's current estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually.

Timing. Cost estimates are based on an assumption that decommissioning will commence promptly after the current NRC operating licensees expire. The operating licenses currently expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2025 and 2027 for the Palo Verde units.

Spent Fuel Dry Storage Costs. Cost estimates are based on an assumption that the DOE will begin to take spent fuel in 2015, and will remove the last spent fuel from the San Onofre and Palo Verde sites by 2045 and 2047, respectively. Costs for spent fuel monitoring are included until 2045 and 2047, respectively.

Changes in decommissioning technology, regulation, and economics. The current cost studies assume the use of current technologies under current regulations and at current cost levels.

Effect if Different Assumptions Used. The ARO for decommissioning SCE's active nuclear facilities was $3.1 billion and $2.9 billion at December 31, 2009 and 2008, respectively. Changes in the estimated costs or timing of decommissioning, or in the assumptions and judgments by management underlying these estimates, could cause material revisions to the estimated total cost to decommission these facilities which could have a material affect on the recorded liability and related regulatory asset. The following table illustrates the increase to

Table of Contents

the ARO and regulatory asset if the escalation rate or discount rate was adjusted while leaving all other assumptions constant:

(in millions)	Increase to ARO and regulatory asset at December 31, 2009
Uniform increase in escalation rate of 25 basis points	$ 20
Decrease in discount rate of 25 basis points	$ 2

Pensions and Postretirement Benefits Other than Pensions

Nature of Estimate Required. Authoritative accounting guidance requires companies to recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as assets and liabilities in the balance sheet; the assets and/or liabilities are normally offset through other comprehensive income (loss). In accordance with authoritative guidance for rate-regulated enterprises, regulatory assets and liabilities are recorded instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. Edison International has a fiscal year-end measurement date for all of its postretirement plans.

Key Assumptions of Approach Used. Pension and other postretirement obligations and the related effects on results of operations are calculated using actuarial models. Two critical assumptions, discount rate and expected return on assets, are important elements of plan expense and liability measurement. Additionally, health care cost trend rates are critical assumptions for postretirement health care plans. These critical assumptions are evaluated at least annually. Other assumptions, which require management judgment, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

As of December 31, 2009, Edison International's pension plans had a $3.7 billion benefit obligation and total expense for these plans was $140 million for 2009. As of December 31, 2009, Edison International's PBOP plans had a $2.1 billion benefit obligation and total expense for these plans was $82 million for 2009. The following are critical assumptions used to determine expense for pension and other postretirement benefit obligations as of December 31, 2009:

(in millions)	Pension Plans	Postretirement Benefits Other than Pensions
Discount rate[1]	6.25%	6.25%
Expected long-term return on plan assets[2]	7.5%	7.0%
Assumed health care cost trend rates[3]		8.75%

1 The discount rate enables Edison International to state expected future cash flows at a present value on the measurement date. Edison International selects its discount rate by performing a yield curve analysis. This analysis determines the equivalent discount rate on projected cash flows, matching the timing and amount of expected benefit payments. Two corporate yield curves were considered, Citigroup and AON.

2 To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. A portion of PBOP trusts asset returns are subject to taxation, so the 7.0% rate of return on plan assets above is determined on an after-tax basis. Actual time-weighted, annualized returns on the pension plan assets were 24.4%, 3.7% and 4.1% for the one-year, five-year and ten-year periods ended December 31, 2009, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 23.6%, 1.9%, and 1.5% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

3 The health care cost trend rate is 8.75% for 2009, gradually declining to 5.5% for 2016 and beyond.

Pension expense is recorded for SCE based on the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense calculated in accordance with authoritative accounting guidance for pension is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2009, this cumulative difference amounted to a regulatory asset of $24 million, meaning that the accounting method has recognized $24 million more in expense than the rate-making method since implementation of authoritative guidance for employers' accounting for pensions in 1987.

Edison International's pension and PBOP plans are subject to limits established for federal tax deductibility. SCE funds its pension and PBOP plans in accordance with amounts allowed by the CPUC. Executive pension plans and competitive power generation PBOP plans have no plan assets.

Effect if Different Assumptions Used. Changes in the estimated costs or timing of pension and other postretirement benefit obligations, or the assumptions and judgments used by management underlying these estimates, could have a material affect on the recorded expenses and liabilities. Edison International's total annual contributions for SCE are recovered through CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to SCE's total annual expense.

Table of Contents

A one percentage point increase in the discount rate would decrease the projected benefit obligation for pension by $288 million. A one percentage point decrease in the discount rate would increase the projected benefit obligation for pension by $294 million. A one percentage point increase in the expected rate of return on pension plan assets would decrease the expense by $23 million.

A one percentage point increase in the discount rate for PBOP would decrease the projected benefit obligation by $238 million. A one percentage point decrease in the discount rate for the PBOP would increase the projected benefit obligation by $269 million. A one percentage point increase in the expected rate of return on PBOP plan assets would decrease the expense by $12 million. Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2009 by $226 million and annual aggregate service and interest costs by $15 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2009 by $206 million and annual aggregate service and interest costs by $14 million.

Income Taxes

Nature of Estimates Required. As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes for each jurisdiction in which it operates. This process involves estimating actual current period tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet.

Edison International takes certain tax positions it believes are applied in accordance with the applicable tax laws. However, these tax positions are subject to interpretation by the IRS, state tax authorities and the courts. Edison International determines its uncertain tax positions in accordance with the authoritative guidance.

Key Assumptions and Approach Used. Accounting for tax obligations requires management judgment. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that a tax position will be sustained, and to determine the amount of tax benefits to be recognized. Judgment is also used in determining the likelihood a tax position will be settled and possible settlement outcomes. In assessing its uncertain tax positions Edison International considers, among others, the following factors: the facts and circumstances of the position, regulations, rulings, and case law, opinions or views of legal counsel and other advisers, and the experience gained from similar tax positions. Management evaluates uncertain tax positions at the end of each reporting period and makes adjustments when warranted based on changes in fact or law.

Effect if Different Assumptions Used. Actual income taxes may differ from the estimated amounts which could have a significant impact on the liabilities, revenue and expenses recorded in the financial statements. Edison International continues to be under audit or subject to audit for multiple years in various jurisdictions. Significant judgment is required to determine the tax treatment of particular tax positions that involve interpretations of complex tax laws. A tax liability has been recorded with respect to tax positions in which the outcome is uncertain and the effect is estimable. Such liabilities are based on judgment and a final determination could take many years from the time the liability is recorded. Furthermore, settlement of tax positions included in open tax years may be resolved by compromises of tax positions based on current factors and business considerations that may result in material adjustments to income taxes previously estimated. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Income Taxes" for a further discussion on income taxes.

Impairment of Long-Lived Assets

Nature of Estimates Required. EME evaluates its long-lived assets, including intangible assets, for impairment in accordance with applicable authoritative guidance. The amount of the impairment charges, if applicable, are calculated as the excess of the asset's carrying value over its fair value, which represents the discounted expected future cash flows attributable to the asset or, in the case of assets expected to be sold, at fair value less costs to sell. Authoritative guidance requires that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, asset impairment must be recognized on the financial statements. EME evaluates its long-lived assets for impairment whenever indicators of impairment exist or when EME commits to sell the asset. These evaluations may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as economic or operational analyses. If the carrying amount is not recoverable, an impairment charge is recorded.

Key Assumptions and Approach Used. The assessment of impairment requires significant management judgment to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors that EME considers important, which could trigger an impairment, include operating losses from a project, projected future operating losses, the financial condition of counterparties, or significant negative industry or economic trends. The determination of fair value requires management to apply judgment in: (1) estimating future prices of energy and capacity in wholesale energy markets and fuel prices that are susceptible to significant change, (2) environmental and maintenance expenditures, and (3) the time period due to the length of the estimated remaining useful lives.

Effect if Different Assumptions Used. The estimates and assumptions used to determine whether an impairment exists are subject to a high degree of uncertainty. The estimated fair value of an asset would change materially if different estimates and assumptions were used to determine the amounts or timing of future revenues, environmental compliance costs or operating expenditures. If actual results are not consistent with the assumptions used in estimating future cash flows and asset fair values, EME may be exposed to additional losses that could be material to EME's results of operations.

Table of Contents

Merchant Coal-Fired Power Plants

Weak commodity prices and heightened public policy pressure on coal generation have resulted in continuing uncertainties for merchant coal-fired power plants similar to EME's, which may require significant capital and increased operating costs to meet environmental requirements. Management has reviewed long-term cash flow forecasts that included assumptions about future electricity and fuel prices, future capacity payments under the PJM RPM, and future capital expenditure requirements under different scenarios. Assumptions included in the long-term cash flow forecasts included:

- Observable market prices for electricity and fuel to the extent available and long-term prices developed based on a fundamental price model;
- Long-term capacity prices based on the assumption that the PJM RPM capacity market would continue consistent with its current structure, with expected increases in revenue as a result of declines in reserve margins beyond the price of the latest auctions; and
- Multiple plans for compliance with environmental regulations.

If commodity prices do not increase consistent with the fundamental forecast or if EME decides not to install additional environmental control equipment and, instead, shuts down one or more coal-fired power plants, the forecasted cash flow would be less than expected. If the undiscounted expected cash flow measured at a plant level were less than the net book value of the asset group, an impairment charge would be recognized. The amount of an impairment charge would be calculated as the excess of the net book value of the asset group over its fair value, which generally represents the discounted future cash flows attributable to the asset group.

If EME decides to implement an environmental compliance plan that results in shutting down one or more coal-fired power plants or results in a shorter useful life, in addition to preparing an impairment analysis and possibly recording a related impairment of the plant, the remaining useful life of the plant would need to be adjusted to reflect the revised shorter life. The impact on annual depreciation could be significant.

EME includes allocated acquired emission allowances as part of each power plant asset group. In the case of the Powerton and Joliet Stations, EME also includes prepaid rent in the respective asset group. EME's unit of account is at the plant level and, accordingly, the closure of a unit at a multi-unit site would not result in an impairment of property, plant and equipment unless such condition were to affect an impairment assessment on the entire plant.

Accounting for Contingencies, Guarantees and Indemnities

Nature of Estimates Required. Edison International records loss contingencies when it determines that the outcome of future events is probable of occurring and when the amount of the loss can be reasonably estimated. When a guarantee or indemnification subject to authoritative guidance is entered into, Edison International records a liability for the estimated fair value of the underlying guarantee or indemnification. Gain contingencies are recognized in the financial statements when they are realized.

Table of Contents

Key Assumptions and Approach Used. The determination of a reserve for a loss contingency is based on management judgment and estimates with respect to the likely outcome of the matter, including the analysis of different scenarios. Liabilities are recorded or adjusted when events or circumstances cause these judgments or estimates to change. In assessing whether a loss is a reasonable possibility, Edison International may consider the following factors, among others: the nature of the litigation, claim or assessment, available information, opinions or views of legal counsel and other advisors, and the experience gained from similar cases. Edison International provides disclosures for material contingencies when there is a reasonable possibility that a loss or an additional loss may be incurred. Some guarantees and indemnifications could have a significant financial impact under certain circumstances, and management also considers the probability of such circumstances occurring when estimating the fair value.

Effect if Different Assumptions Used. Actual amounts realized upon settlement of contingencies may be different than amounts recorded and disclosed and could have a significant impact on the liabilities, revenue and expenses recorded on the consolidated financial statements. In addition, for guarantees and indemnities actual results may differ from the amounts recorded and disclosed and could have a significant impact on Edison International's consolidated financial statements. For a discussion of contingencies, guarantees and indemnities, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Commitments and Contingencies."

New Accounting Guidance

New accounting guidance are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 1. Summary of Significant Accounting Policies New Accounting Guidance."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is included in the MD&A under the headings "SCE: Market Risk Exposures" and "EMG: Market Risk Exposures."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Shareholders of Edison International

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in equity present fairly, in all material respects, the financial position of Edison International (the "Company") and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes, 1, 4, and 10 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007, margin and cash collateral deposits related to derivative positions and fair value measurement and disclosure principles as of January 1, 2008, and noncontrolling interests as of January 1, 2009.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
March 1, 2010

Table of Contents

Consolidated Statements of Income **Edison International**

(in millions, except per-share amounts)	Years ended December 31, 2009	2008	2007
Electric utility	$ 9,959	$ 11,246	$ 10,231
Competitive power generation	2,374	2,808	2,575
Financial services and other	28	58	62
Total operating revenue	12,361	14,112	12,868
Fuel	1,517	2,147	1,875
Purchased power	2,751	3,845	3,235
Operations and maintenance	4,387	4,288	4,065
Depreciation, decommissioning and amortization	1,418	1,313	1,181
Lease terminations and other	890	(44)	3
Total operating expenses	10,963	11,549	10,359
Operating income	1,398	2,563	2,509
Interest and dividend income	32	62	154
Equity in income from partnerships and unconsolidated subsidiaries net	42	31	79
Other income	171	113	95
Interest expense net of amounts capitalized	(732)	(700)	(752)
Other expenses	(57)	(125)	(45)
Loss on early extinguishment of debt			(241)
Income from continuing operations before income taxes	854	1,944	1,799
Income tax expense (benefit)	(98)	596	492
Income from continuing operations	952	1,348	1,307
Loss from discontinued operations net of tax	(7)		(2)
Net income	945	1,348	1,305
Less: Net income attributable to noncontrolling interests	96	133	207
Net income attributable to Edison International common shareholders	$ 849	$ 1,215	$ 1,098
Amounts attributable to Edison International common shareholders:			
Income from continuing operations, net of tax	$ 856	$ 1,215	$ 1,100
Loss from discontinued operations, net of tax	(7)		(2)
Net income attributable to Edison International common shareholders	$ 849	$ 1,215	$ 1,098
Basic earnings per common share attributable to Edison International common shareholders:			
Weighted-average shares of common stock outstanding	326	326	326
Continuing operations	$ 2.61	$ 3.69	$ 3.34
Discontinued operations	(0.02)		(0.01)
Total	$ 2.59	$ 3.69	$ 3.33

Diluted earnings per common share attributable to Edison International common shareholders:						
Weighted-average shares of common stock outstanding, including effect of dilutive securities		327		329		331
Continuing operations	$	2.60	$	3.68	$	3.32
Discontinued operations		(0.02)				(0.01)
Total	$	2.58	$	3.68	$	3.31
Dividends declared per common share	$	1.245	$	1.225	$	1.175

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

Table of Contents

Consolidated Statements of Comprehensive Income **Edison International**

(in millions)	Years ended December 31, 2009	2008	2007
Net income	$ 945	$ 1,348	$ 1,305
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	4	(3)	(2)
Pension and postretirement benefits other than pensions:			
Net loss arising during the period	(13)	(36)	(2)
Amortization of net loss included in net income	13		5
Prior service cost arising during the period		(1)	
Amortization of prior service cost included in expense	1	(1)	(1)
Unrealized gain (loss) on derivatives qualified as cash flow hedges:			
Unrealized holding gain (loss) arising during the period, net of income tax expense (benefit) of $36, $138 and $(160) for 2009, 2008 and 2007, respectively	43	211	(234)
Reclassification adjustments included in net income, net of income tax expense (benefit) of $(124), $58 and $45 for 2009, 2008 and 2007, respectively	(178)	89	64
Other comprehensive income (loss)	(130)	259	(170)
Comprehensive income	815	1,607	1,135
Less: Comprehensive income attributable to noncontrolling interests	96	133	207
Comprehensive income attributable to Edison International	$ 719	$ 1,474	$ 928

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

Table of Contents

Consolidated Balance Sheets **Edison International**

	December 31,	
(in millions)	**2009**	**2008**
ASSETS		
Cash and equivalents	$ 1,673	$ 3,916
Short-term investments	10	7
Receivables, less allowances of $53 and $39 for uncollectible accounts at respective dates	1,017	1,006
Accrued unbilled revenue	347	328
Inventory	533	553
Derivative assets	357	327
Restricted cash	69	3
Margin and collateral deposits	125	105
Regulatory assets	120	605
Deferred income taxes	3	104
Other current assets	176	399
Total current assets	4,430	7,353
Competitive power generation and other property less accumulated depreciation of $2,231 and $2,019 at respective dates	5,147	5,374
Nuclear decommissioning trusts	3,140	2,524
Investments in partnerships and unconsolidated subsidiaries	216	229
Investments in leveraged leases	160	2,467
Other investments	91	89
Total investments and other assets	8,754	10,683
Utility plant, at original cost:		
Transmission and distribution	22,214	20,006
Generation	2,667	1,819
Accumulated depreciation	(5,921)	(5,570)
Construction work in progress	2,701	2,454
Nuclear fuel, at amortized cost	305	260
Total utility plant	21,966	18,969
Derivative assets	268	244
Restricted deposits	43	43
Rent payments in excess of levelized rent expense under plant operating leases	1,038	878
Regulatory assets	4,139	5,414
Other long-term assets	806	1,031
Total long-term assets	6,294	7,610
Total assets	$ 41,444	$ 44,615

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

Table of Contents

Consolidated Balance Sheets **Edison International**

(in millions, except share amounts)	December 31, 2009	December 31, 2008
LIABILITIES AND EQUITY		
Short-term debt	$ 85	$ 2,143
Current portion of long-term debt	377	174
Accounts payable	1,123	1,031
Accrued taxes	186	590
Accrued interest	196	187
Customer deposits	238	228
Book overdrafts	224	224
Derivative liabilities	107	178
Regulatory liabilities	367	1,111
Other current liabilities	884	831
Total current liabilities	3,787	6,697
Long-term debt	10,437	10,950
Deferred income taxes	4,334	5,717
Deferred investment tax credits	102	109
Customer advances	119	137
Derivative liabilities	529	776
Pensions and benefits	2,061	2,860
Asset retirement obligations	3,241	3,042
Regulatory liabilities	3,328	2,481
Other deferred credits and other long-term liabilities	2,500	1,137
Total deferred credits and other liabilities	16,214	16,259
Total liabilities	30,438	33,906
Commitments and contingencies (Note 6)		
Common stock, no par value (800,000,000 shares authorized; 325,811,206 shares issued and outstanding at each date)	2,304	2,272
Accumulated other comprehensive income	37	167
Retained earnings	7,500	7,078
Total Edison International's common shareholders' equity	9,841	9,517
Noncontrolling interests	258	285
Preferred and preference stock of utility not subject to mandatory redemption	907	907
Total equity	11,006	10,709
Total liabilities and equity	$ 41,444	$ 44,615

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

Table of Contents

Consolidated Statements of Cash Flows **Edison International**

(in millions)	Years ended December 31, 2009	2008	2007
Cash flows from operating activities:			
Net income	$ 945	$ 1,348	$ 1,305
Loss from discontinued operations	7		2
Income from continuing operations	952	1,348	1,307
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	1,418	1,313	1,181
Regulatory impacts of net nuclear decommissioning trust earnings (reflected in accumulated depreciation)	158	(10)	143
Other amortization	120	106	111
Lease terminations and other	888	(44)	3
Stock-based compensation	22	34	37
Equity in income from partnerships and unconsolidated subsidiaries net	(42)	(31)	(75)
Distributions and dividends from unconsolidated entities	31	(8)	33
Deferred income taxes and investment tax credits	(1,457)	207	(39)
Income from leveraged leases	(14)	(51)	(49)
Loss on early extinguishment of debt			241
Changes in operating assets and liabilities:			
Receivables	80	128	8
Inventory	20	(114)	(41)
Restricted cash	(69)		
Margin and collateral deposits net of collateral received	30	(19)	75
Other current assets	202	(48)	(147)
Rent payments in excess of levelized rent expense	(160)	(162)	(160)
Accounts payable	152	(176)	28
Accrued taxes	(402)	340	47
Book overdrafts		16	72
Other current liabilities	31	(39)	(30)
Derivative assets and liabilities net	(581)	849	(193)
Regulatory assets and liabilities net	1,457	(2,946)	679
Other assets	62	224	(180)
Other liabilities	154	1,344	195
Operating cash flows from discontinued operations	(7)		(2)
Net cash provided by operating activities	3,045	2,261	3,244
Cash flows from financing activities:			
Long-term debt issued	939	2,632	2,930
Premiums paid on extinguishment of debt and long-term debt issuance costs	(25)	(21)	(241)
Long-term debt repaid	(1,044)	(295)	(3,215)
Bonds repurchased	(219)	(212)	(37)
Preferred stock redeemed		(7)	
Rate reduction notes repaid			(246)
Short-term debt financing net	(2,058)	1,643	500
Cash contributions from noncontrolling interests	2	12	
Stock-based compensation net	(3)	(26)	(84)
Dividends and distributions to noncontrolling interests	(117)	(170)	(157)
Dividends paid	(404)	(397)	(378)

Net cash provided (used) by financing activities	$ (2,929)	$ 3,159	$ (928)

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

Table of Contents

Consolidated Statements of Cash Flows **Edison International**

(in millions)	Years ended December 31, 2009	2008	2007
Cash flows from investing activities:			
Capital expenditures	$ (3,282)	$ (2,824)	$ (2,826)
Purchase of interest in acquired companies	(22)	(19)	(33)
Proceeds from termination of leases	1,420		
Proceeds from sale of property and interests in projects	7	113	2
Proceeds from sale of nuclear decommissioning trust investments	2,217	3,130	3,697
Purchases of nuclear decommissioning trust investments and other	(2,416)	(3,137)	(3,830)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment	11	65	42
Maturities and sale of short-term investments	4	96	9,953
Purchase of short-term investments	(7)	(22)	(9,476)
Restricted cash	4	4	99
Investments in other assets	(295)	(351)	(298)
Net cash used by investing activities	(2,359)	(2,945)	(2,670)
Net increase (decrease) in cash and equivalents	(2,243)	2,475	(354)
Cash and equivalents, beginning of year	3,916	1,441	1,795
Cash and equivalents, end of year	$ 1,673	$ 3,916	$ 1,441

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

Table of Contents

Consolidated Statements of Changes in Equity **Edison International**

(in millions)	Equity Attributable to Edison International: Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Subtotal	Noncontrolling Interests: Other	Preferred and Preference Stock	Total Equity
Balance at December 31, 2006	$ 2,080	$ 78	$ 5,551	$ 7,709	$ 271	$ 915	$ 8,895
Net income			1,098	1,098	156	51	1,305
Adoption of accounting guidance for uncertainty in income taxes			250	250			250
Other comprehensive loss		(170)		(170)			(170)
Common stock dividends declared ($1.175 per share)			(383)	(383)			(383)
Dividends, distributions to noncontrolling interests and other					(132)	(51)	(183)
Stock-based compensation net	45		(130)	(85)			(85)
Noncash stock-based compensation and other	32		(7)	25			25
Change in classification of shares purchased to settle performance shares	68		(68)				
Balance at December 31, 2007	$ 2,225	$ (92)	$ 6,311	$ 8,444	$ 295	$ 915	$ 9,654
Net income			1,215	1,215	82	51	1,348
Other comprehensive income		259		259			259
Common stock dividends declared ($1.225 per share)			(399)	(399)			(399)
Preferred stock redeemed, net of gain	2			2		(8)	(6)
Dividends, distributions to noncontrolling interests and other					(92)	(51)	(143)
Stock-based compensation net	10		(36)	(26)			(26)
Noncash stock-based compensation and other	35		(13)	22			22
Balance at December 31, 2008	$ 2,272	$ 167	$ 7,078	$ 9,517	$ 285	$ 907	$ 10,709
Net income			849	849	45	51	945
Other comprehensive loss		(130)		(130)			(130)
Common stock dividends declared ($1.245 per share)			(406)	(406)			(406)
Dividends, distributions to noncontrolling interests and other					(72)	(51)	(123)
Stock-based compensation net	9		(12)	(3)			(3)
Noncash stock-based compensation and other	23		(9)	14			14
Balance at December 31, 2009	$ 2,304	$ 37	$ 7,500	$ 9,841	$ 258	$ 907	$ 11,006

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

Table of Contents

Notes to Consolidated Financial Statements

Note 1. Summary of Significant Accounting Policies

Edison International's principal wholly owned subsidiaries include: SCE, a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California; and EMG, a wholly owned non-utility subsidiary; EMG is the holding company of EME and Edison Capital. EME is a holding company whose subsidiaries and affiliates are engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities; EME also conducts hedging and energy trading activities in competitive power markets. Edison Capital is a provider of capital and financial services. EME has domestic projects and one foreign project in Turkey; Edison Capital has domestic and foreign investments, primarily in Europe, Australia and Africa.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International consolidates subsidiaries in which it has a controlling interest and VIEs in which it is the primary beneficiary. In addition, Edison International generally uses the equity method to account for significant interests in (1) partnerships and subsidiaries in which it owns a significant but less than controlling interest and (2) VIEs in which it is not the primary beneficiary. Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates.

Edison International's accounting policies conform to accounting principles generally accepted in the United States of America, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC. SCE applies authoritative guidance for rate-regulated enterprises to the portion of its operations in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of electric utility revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; and conversely the principles allow recording of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. See Note 11 for composition of regulatory assets and liabilities.

Financial statements prepared in conformity with accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingency assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results could differ from those estimates.

Edison International has performed an evaluation of subsequent events through the date the financial statements were issued.

Table of Contents

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 income, respectively. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. AFUDC-equity represents a method to compensate SCE for the estimated cost of equity used to finance utility plant additions and is recorded as part of construction in progress. AFUDC equity was $116 million in 2009, $54 million in 2008 and $46 million in 2007. AFUDC debt was $32 million in 2009, $27 million in 2008 and $24 million in 2007.

In 2007, FERC issued an order granting ROE incentive adders, recovery of the ROE and incentive adders during the construction phase (referred to as CWIP) and recovery of abandoned plant costs for three of SCE's transmission projects: DPV2, Tehachapi and Rancho Vista. In addition, the FERC granted an incentive for CAISO participation. The order permits SCE to include 100% of prudently-incurred capital expenditures in rate base during construction of the three projects and earn a return on equity, rather than capitalizing AFUDC.

Book Overdrafts

Book overdrafts represent timing difference associated with outstanding checks in excess of cash funds that are on deposit with financial institutions. SCE's ending daily cash funds are temporarily invested in cash equivalents until required for check clearings. SCE reclassifies the amount for checks issued but not yet paid by the financial institution, from cash to book overdrafts.

Cash and Equivalents

Cash and cash equivalents as of December 31, 2009 and 2008 consisted of the following:

	December 31,	
(in millions)	**2009**	**2008**
Cash	$ 216	$ 138
Cash Equivalents:		
Money market funds	1,457	3,583
U.S. government agency securities		164
Commercial paper		30
Time deposits (certificates of deposit)		1
Total cash equivalents	1,457	3,778
Total cash and equivalents	$ 1,673	$ 3,916

Cash equivalents, with the exception of money market funds, were stated at amortized cost plus accrued interest. The carrying value of cash equivalents equals the fair value as all investments have maturities of less than three months. For further discussion of money market funds, see Note 10. Included in cash and equivalents is $92 million and $89 million at

Table of Contents

December 31, 2009 and 2008, respectively, for four projects that Edison International is consolidating in accordance with authoritative accounting guidance for VIEs. For a discussion of restricted cash, see "Restricted Cash."

Deferred Financing Costs

Debt premium, discount and issuance expenses are deferred and amortized (on a straight-line basis for SCE and on a basis which approximates the effective interest rate method for EMG) through interest expense over the life of each related issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. SCE had unamortized loss on reacquired debt of $287 million and $309 million at December 31, 2009 and 2008, respectively, reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. Edison International had unamortized debt issuance costs of $93 million and $86 million at December 31, 2009 and 2008, respectively, reflected in "Other long-term assets" on the consolidated balance sheets. Amortization of deferred financing costs charged to interest expense was $31 million, $28 million and $30 million in 2009, 2008 and 2007, respectively.

Derivative Instruments and Hedging Activities

Edison International records its derivative instruments on its consolidated balance sheets at fair value as either assets or liabilities unless they meet the definition of a normal purchase or sale or are classified as VIEs or leases. The derivative instrument fair values are marked to market at each reporting period. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Changes in the fair value of SCE's derivative instruments are expected to be recovered from or refunded to customers through regulatory mechanisms and therefore, SCE's fair value changes have no impact on purchased-power expense or earnings. SCE does not use hedge accounting for derivative transactions due to the regulatory accounting treatment.

EME's changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met which requires EME to formally document, designate, and assess the effectiveness of hedge transactions. For those derivative transactions that qualify for, and for which EME has elected hedge accounting, gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of a designated fair value hedge. For a designated hedge of the cash flows of a forecasted transaction or a foreign currency exposure, the effective portion of the gain or loss is initially recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income (loss)," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when there is a legal right of offset, such as multiple contracts executed with the same counterparty under master netting arrangements. In addition, derivative positions are offset against margin and cash collateral deposits as discussed below in "Margin and Collateral Deposits." The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception is recorded on the consolidated balance sheets at fair value. Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases.

EME's risk management and trading operations are conducted by a subsidiary. As a result of a number of industry and credit-related factors, the subsidiary has minimized its price risk management and trading activities not related to EME's power plants or investments in energy projects. To the extent it engages in trading activities, EME's trading subsidiary seeks to manage price risk and to create stability of future income by selling electricity in the forward markets and, to a lesser degree, to generate profit from price volatility of electricity and fuels by buying and selling these commodities in wholesale markets. EME generally balances forward sales and purchase contracts and manages its exposure through a value at risk analysis for trading positions and gross margin at risk analysis for hedge positions. Financial instruments that are utilized for trading purposes are measured at fair value and are included in the consolidated balance sheets as derivative assets or liabilities. In the absence of quoted market prices, financial instruments are valued at fair value, considering time value, volatility of the underlying commodity, and other factors as determined by EME. Fair value changes for EME's trading operations are reflected in competitive power generation revenues. Derivative assets include the fair value of open financial positions related to trading activities and the present value of net amounts receivable from structured transactions. Derivative liabilities include the fair value of open financial positions related to trading activities.

EME has nontrading derivative financial instruments arising from energy contracts related to the Illinois plants and Homer City. In assessing the fair value of its nontrading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of the commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. EME's unrealized gains and losses from its energy contracts are classified as part of competitive power generation revenue.

Dividend Restrictions

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the 48% authorized level on a 13-month weighted average basis. At December 31, 2009, SCE's 13-month weighted-average common equity

Table of Contents

component of total capitalization was 49.8% resulting in the capacity to pay $271 million in additional dividends.

Earnings Per 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 attributable to Edison International common shareholders was computed as follows:

(in millions)	**Years ended December 31, 2009**	**2008**	**2007**
Basic earnings per share continuing operations:			
Income from continuing operations attributable to common shareholders, net of tax	$ 856	$ 1,215	$ 1,100
Gain on redemption of preferred stock		2	
Participating securities dividends	(6)	(14)	(12)
Income from continuing operations available to common shareholders	$ 850	$ 1,203	$ 1,088
Weighted average common shares outstanding	326	326	326
Basic earnings per share continuing operations	$ 2.61	$ 3.69	$ 3.34
Diluted earnings per share continuing operations:			
Income from continuing operations available to common shareholders	$ 850	$ 1,203	$ 1,088
Income impact of assumed conversions	1	8	12
Income from continuing operations available to common shareholders and assumed conversions	$ 851	$ 1,211	$ 1,100
Weighted average common shares outstanding	326	326	326
Incremental shares from assumed conversions	1	3	5
Adjusted weighted average shares diluted	327	329	331
Diluted earnings per share continuing operations	$ 2.60	$ 3.68	$ 3.32

Stock-based compensation awards to purchase 8,547,090, 3,848,546 and 83,901 shares of common stock for the years ended December 31, 2009, 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; and therefore, the effect would have been antidilutive.

Table of Contents

Impairment of Equity Method Investments and Long-Lived Assets

Edison International evaluates the impairment of its investments in projects and other long-lived assets based on a review of estimated future cash flows expected to be generated whenever events or changes in circumstances indicate the carrying amount of such investments or assets may not be recoverable. If the carrying amount for an equity method investment exceeds fair value, an impairment loss is recorded if the decline is other than temporary. If the carrying amount of a long-lived asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, an impairment loss is recognized. In accordance with authoritative guidance for rate regulated enterprises, SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from ratepayers.

Income Taxes

Edison International's eligible subsidiaries are included in Edison International's consolidated federal income tax and combined state tax returns. Edison International has tax-allocation and payment agreements with certain of its subsidiaries. For subsidiaries other than SCE, the right of a participating subsidiary to receive or make a payment and the amount and timing of tax-allocation payments are dependent on the inclusion of the subsidiary in the consolidated income tax returns of Edison International and other factors including the consolidated taxable income of Edison International and its includible subsidiaries, the amount of taxable income or net operating losses and other tax items of the participating subsidiary, as well as the other subsidiaries of Edison International. There are specific procedures regarding allocations of state taxes. Each subsidiary is eligible to receive tax-allocation payments for its tax losses or credits only at such time as Edison International and its subsidiaries generate sufficient taxable income to be able to utilize the participating subsidiary's losses in the consolidated income tax return of Edison International. Pursuant to an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed its federal and state income tax returns on a separate return basis.

As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes for each jurisdiction in which it operates. This involves estimating current period tax expense along with assessing temporary differences resulting from differing treatment of items (such as depreciation) for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest income, interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income. Investment tax credits are deferred and amortized to income tax expense over the lives of the properties and production tax credits are recognized in income tax expense in the period in which they are earned.

Edison International believes that the positions it takes on filed tax returns are in accordance with tax laws. However, these positions are subject to interpretation by the IRS, state tax authorities and the courts. In accordance with authoritative guidance related to accounting for

Table of Contents

uncertainty in income taxes, Edison International applies judgment to assess each tax position taken on filed tax returns and tax positions expected to be taken on future returns to determine whether a tax position is more likely than not to be sustained and, therefore, will be recognized in the financial statements. However, all temporary tax positions, whether or not the more likely than not to be sustained threshold is met, are recorded in the financial statements in accordance with the measurement principles of the authoritative guidance. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained. Management evaluates its income tax exposures at each reporting date and records valuation allowances and/or reserves as appropriate, which are reflected in the captions "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets.

Intangible Assets

Edison International accounts for EME's acquired intangible assets in accordance with authoritative guidance which establishes that acquired intangible assets with indefinite lives are not amortized, rather they are tested at least annually for impairment or when events or changes in circumstances indicate that the asset might be impaired. Intangible assets are periodically reviewed when impairment indicators are present to assess recoverability from future operations using undiscounted future cash flows. For project development rights, the assets are subject to ongoing impairment analysis, such that if a project is no longer expected, the capitalized costs are written off.

"Other current assets" on Edison International's consolidated balance sheets includes emission allowances purchased for use by EME of $51 million and $88 million at December 31, 2009 and 2008, respectively. "Other long-term assets" on Edison International's consolidated balance sheets include EME's project development rights, option rights, and purchased emission allowances totaling $48 million and $73 million at December 31, 2009 and 2008, respectively. Amortizable intangible assets are amortized using the straight-line method over five years. Emission allowances at EME's fossil-fueled facilities decreased in 2009 due to a decline in market prices of purchased emission allowances in 2009, compared to 2008, and usage of existing emission allowances.

Inventory

Inventory is stated at the lower of cost or market, cost being determined by the weighted-average cost method for fuel, and the average cost method for materials and supplies. Inventory at December 31, 2009 and 2008 consisted of the following:

	December 31,	
(in millions)	**2009**	**2008**
Coal, gas, fuel oil and raw materials	$ 158	$ 163
Spare parts, materials and supplies	375	390
Total	$ 533	$ 553

Table of Contents

Leases

Minimum lease payments under operating leases for property, plant and equipment are levelized (total minimum lease payments divided by the number of years of the lease) and recorded as rent expense over the terms of the leases. Lease payments in excess of the minimum are recorded as rent expense in the year incurred.

Capital leases are reported as long-term obligations on the consolidated balance sheets under the caption "Other deferred credits and other long-term liabilities." In accordance with authoritative guidance for rate-regulated enterprises, SCE's capital lease amortization expense and interest expense are reflected in the caption "Purchased power" on the consolidated statements of income.

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers and cash received from counterparties and brokers (reflected in "Other current liabilities" on the consolidated balance sheets) as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the value of the positions. In accordance with authoritative guidance which allows for netting of counterparty receivables and payables under a master netting arrangement, Edison International presents a portion of its margin and cash collateral deposits net with its derivative positions on its consolidated balance sheets. Cash collateral provided to others that has been offset against derivative liabilities totaled $49 million and $123 million at December 31, 2009 and 2008, respectively. Collateral received from others that has been offset against derivative assets totaled $124 million and $225 million at December 31, 2009 and 2008, respectively. Collateral provided to others that has not been offset against derivative liabilities totaled $125 million and $105 million at December 31, 2009 and 2008, respectively. Cash collateral received from others that has not been offset against derivative assets totaled $59 million and $8 million at December 31, 2009 and 2008 respectively.

New Accounting Guidance

Accounting Guidance Adopted in 2009

General Principles

The FASB issued an accounting standard establishing the FASB Accounting Standards Codification (Codification) as the source of authoritative, nongovernmental U.S. GAAP superseding existing FASB, American Institute of Certified Public Accountants (AICPA), Emerging Issues Task Force (EITF) and related literature. Following this action, the FASB will not issue new standards in the form of Statements, FASB Staff Positions or EITF Abstracts. Instead, the FASB will issue Accounting Standards Updates. Two levels of U.S. GAAP will exist: authoritative and non-authoritative. The Codification is not intended to change U.S. GAAP or guidance issued by the U.S. Securities and Exchange Commission. Edison International adopted the Codification effective July 1, 2009.

Table of Contents

Subsequent Events

The FASB issued authoritative guidance that sets forth the period subsequent to the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; the circumstances under which an entity should recognize these events or transactions; and the disclosures that an entity should make. Edison International adopted this guidance effective April 1, 2009. Edison International also adopted revised disclosure requirements prescribed by an accounting standards update issued in February 2010. The adoption had no impact on Edison International's consolidated results of operations, financial position or cash flows.

Fair Value Measurements and Disclosures

The FASB issued an accounting standards update that provides additional guidance on how companies should measure the fair value of certain alternative investments such as hedge funds, private equity funds, venture capital funds and fund of funds. This update is designed to address concerns regarding how to appropriately adjust the Net Asset Value (NAV) of these investments to reflect specific attributes, including redemption restrictions and capital commitments. If the investee's underlying investments are measured at fair value at the investor's measurement date, this update allows investors to use NAV to estimate the fair value unless it is probable the investment will be sold at something other than NAV. If not calculated as of the reporting entity's measurement date, the NAV must be adjusted for significant market events. This update provides guidance on fair value hierarchy classification and also requires enhanced disclosures. Edison International adopted this guidance on October 1, 2009. The adoption had no impact on its investments which primarily consist of the nuclear decommissioning trusts and certain investments in the defined benefit pension and PBOP plans and the related funded status of these plans recorded on Edison International's consolidated balance sheets.

The FASB issued an accounting standards update that provides additional guidance on how companies should measure liabilities at fair value. While reaffirming the existing definition of fair value, the update reintroduced the concept of entry value into the determination of fair value. Entry value is the amount an entity would receive to enter into an identical liability. Under the new guidance, the fair value of a liability is not adjusted to reflect the impact of contractual restrictions that prevent its transfer. If the quoted price of a liability when traded as an asset includes the effect of a credit enhancement (i.e. a guarantee), this effect should be excluded from the measurement of the liability. Edison International adopted this guidance effective October 1, 2009. The adoption had no impact on Edison International's consolidated results of operations, financial position or cash flows.

The FASB issued authoritative guidance affirming the objective of a fair value measurement, which is to identify the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction at the measurement date between market participants ("exit price") under current market conditions. This includes guidance on identifying circumstances that indicate when there is no active market or transactions where the price inputs being used represent distressed or forced sales. If either of these conditions exists, this guidance provides

Table of Contents

additional direction for estimating fair value and requires disclosure of a change in valuation technique (and the related inputs) resulting from the application of this guidance and to quantify its effects, if practicable. This guidance also requires disclosures on a more disaggregated basis for investments in debt and equity securities measured at fair value. Edison International adopted this guidance effective April 1, 2009. The adoption had no impact on Edison International's consolidated results of operations, financial position or cash flows.

The FASB issued authoritative guidance requiring disclosures about the fair value of all financial instruments, for which it is practicable to estimate that fair value, for interim reporting periods as well as annual statements. Edison International adopted this guidance effective April 1, 2009. Since this guidance impacted disclosures only, the adoption did not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

Effective January 1, 2009, Edison International adopted authoritative guidance for nonrecurring fair value measurements of nonfinancial assets and liabilities. The adoption did not have a material impact on Edison International's consolidated results of operations, financial position or cash flows.

Investments Debt and Equity Securities

The FASB amended existing authoritative guidance which determines whether impairment is other than temporary for debt securities. Under this amended guidance, an entity writes down to fair value through earnings impaired debt securities that it currently intends to sell or for which it is more likely than not it will be required to sell before the anticipated recovery. If an entity does not intend and will not be required to sell a debt security but it is probable that the entity will not collect all amounts due, the entity will separate the other-than-temporary impairment into two components: 1) the amount due to credit loss would be recognized in earnings, and 2) the remaining portion would be recognized in other comprehensive income. Edison International adopted this guidance effective April 1, 2009, resulting in increased disclosures. The adoption did not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

Investments Equity Method and Joint ventures

The FASB clarified the accounting for certain transactions and impairment considerations involving equity method investments. Effective January 1, 2009, Edison International adopted this guidance prospectively. The adoption had no impact on its consolidated financial statements.

Business Combinations

The FASB issued authoritative guidance establishing 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. This guidance determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This guidance applies prospectively to business combinations for which the acquisition date is on or after fiscal years beginning on or after January 1, 2009. The initial adoption had no impact on Edison International's consolidated results of operations, financial position or cash flows.

Compensation Retirement Benefits

The FASB issued authoritative guidance requiring additional postretirement benefit plan asset disclosures by employers about the major categories of assets, the inputs and valuation techniques used to measure fair value, the level within the fair value hierarchy, the effect of using significant unobservable inputs (Level 3) and significant concentrations of risk. Edison International adopted this guidance effective December 31, 2009. Since this guidance impacted disclosures only, the adoption did not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

Consolidation

The FASB issued authoritative guidance requiring an entity to present noncontrolling interests that reflect 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 interests to be clearly identified and presented on the face of the consolidated balance sheets and statements of income; changes in ownership interests to 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 to be measured at fair value. Edison International adopted this guidance effective January 1, 2009. In accordance with this guidance, Edison International reclassified "Noncontrolling interests" of $285 million and "Preferred and preference stock of utility not subject to mandatory redemption" of $907 million at December 31, 2008 to a component of equity on Edison International's consolidated balance sheet.

Derivatives and Hedging

The FASB issued authoritative guidance requiring 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. Edison International adopted this guidance effective January 1, 2009. Since this guidance impacted disclosures only, the adoption did not have an impact on Edison International's consolidated results of operations, financial position or cash flows.

Intangibles Goodwill and Other

The FASB issued authoritative guidance amending the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The intent of the guidance is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset under business combinations and other GAAP. Edison International adopted this guidance effective January 1, 2009. The adoption had no impact on Edison International's consolidated results of operations, financial position or cash flows.

Accounting Guidance Not Yet Adopted

Consolidation   Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities

In December 2009, the FASB issued an accounting standards update that changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an ability to direct the activities of the entity that most significantly impact the entity's economic performance and whether the entity has an obligation to absorb losses. This guidance requires a company to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. Edison International will adopt this guidance effective January 1, 2010. EME estimates the impact of adopting this guidance will result in the deconsolidation of certain wind assets totaling $253 million and the consolidation of coal assets totaling $99 million at January 1, 2010. SCE has determined that it will deconsolidate four QF contracts in which SCE has variable interests and which had total assets of $430 million at January 1, 2010. Deconsolidation will not result in a gain or loss.

Fair Value Measurements and Disclosures

In January 2010, the FASB issued an accounting standards update that provides for new disclosure requirements related to fair value measurements. New requirements include the separate disclosure of significant transfers in and out of Levels 1 and 2 and the reasons for the transfers. In addition, the Level 3 reconciliation of fair value measurements using significant unobservable inputs should include gross rather than net information about purchases, sales, issuances and settlements. The update clarified existing disclosure requirements for the level of disaggregation and inputs and valuations techniques. This guidance is effective January 1, 2010 except for the requirement to provide gross Level 3 activity which will be effective January 1, 2011. Since the guidance impacts disclosures only, the adoption will have no impact on Edison International's consolidated results of operations, financial position or cash flows.

Nuclear Decommissioning

SCE recorded the fair value of its liability for AROs related to the decommissioning of its nuclear power facilities in 2003. At that time, SCE adjusted its nuclear decommissioning obligation, capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs and the recovery of costs through the rate-making process. Decommissioning cost estimates are updated in each Nuclear Decommissioning Cost Triennial Proceeding (NDCTP). Once a Commission decision is rendered, a revised ARO layer reflecting the updated cost estimate is established and accreted over the lives of San Onofre and Palo Verde.

Table of Contents

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the NRC. Decommissioning is expected to begin after expiration of the plants' operating licenses. The plants' initial operating licenses are currently set to expire in 2022 for San Onofre Units 2 and 3, unless license renewal proves feasible, and 2024, 2025 and 2027 for Palo Verde units 1, 2 and 3, respectively. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. Amortization of the ARO asset (included within the unamortized nuclear investment) and accretion of the ARO liability are deferred as increases to the ARO regulatory liability account, resulting in no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The cost of removal amounts, in excess of fair value collected for assets not legally required to be removed, are classified as regulatory liabilities.

Due to regulatory recovery of SCE's nuclear decommissioning expense, SCE applies authoritative accounting guidance for rate-regulated enterprises to its nuclear decommissioning activities. As a result, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on electric utility revenue. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust asset and the related regulatory asset or liability and have no impact on electric utility revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the last day of each month and the last day of the previous month. If the fair value on both days is less than the cost for that security, SCE recognizes a loss for the other-than-temporary impairment. If the fair value is greater or less than the cost for that security at the time of sale, SCE recognizes a related realized gain or loss, respectively.

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. These costs are expensed as incurred.

Project Development Costs

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

Table of Contents

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.

In May 2003, the Palo Verde units returned to traditional cost-of-service ratemaking while San Onofre Units 2 and 3 returned to traditional cost-of-service ratemaking in January 2004. SCE's nuclear plant investments made prior to the return to cost-of-service ratemaking are recorded as regulatory assets on its consolidated balance sheets. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the rate-making treatment for these assets.

Estimated useful lives (authorized by the CPUC) and weighted-average useful lives of SCE's property, plant and equipment, are as follows:

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	25 years to 70 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	45 years
Other plant	5 years to 60 years	20 years

Nuclear fuel is recorded as utility plant (nuclear fuel in the fabrication and installation phase is recorded as construction in progress) in accordance with CPUC rate-making procedures. Nuclear fuel is amortized using the units of production method.

Depreciation of utility plant is computed on a straight-line, remaining-life basis. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.2% for 2009, 4.3% for 2008 and 4.2% for 2007. Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for AROs.

Competitive Power Generation and Other Property

Property, plant and equipment, including leasehold improvements and construction in progress, are capitalized at cost and are principally comprised of EME's majority-owned subsidiaries' plants and related facilities and the plant and related facilities of VIEs consolidated by SCE. Depreciation and amortization are computed by using the straight-line method over the useful life of the property, plant and equipment and over the shorter of the lease term or estimated useful life for leasehold improvements. Depreciation expense stated as a percent of average original cost of depreciable competitive power generation and other property was, on a composite basis, 4.0% for 2009, 3.9% for 2008 and 4.0% for 2007. Gains and losses from sale of assets are recognized at the time of the transaction.

Table of Contents

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

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

Power plant facilities	3 to 30 years
Leasehold improvements	Shorter of life of lease or estimated useful life
Emission allowances	25 to 33.75 years
Equipment, furniture and fixtures	3 to 20 years
Land easements	60 years

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

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

	Years Ended December 31,		
(in millions)	**2009**	**2008**	**2007**
Interest incurred	$ 315	$ 311	$ 297
Interest capitalized	(19)	(32)	(24)
	$ 296	$ 279	$ 273

Asset Retirement Obligation

Edison International accounts for its AROs in accordance with authoritative guidance which requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset in an amount equal to the liability. The liability is increased for accretion each period and the capitalized cost is depreciated over the useful life of the related asset. Settlement of an ARO liability for an amount other than its recorded amount results in a gain or loss. Edison International's conditional AROs are recorded at fair value in the period in which they are incurred if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. AROs related to decommissioning of SCE's nuclear power facilities are based on site-specific studies. Those site-specific studies are updated with each NDCTP. The initial establishment of a nuclear-related ARO is at fair value and results in a corresponding regulatory asset. Subsequent layers of an ARO are established for updated site-specific decommissioning cost estimates stemming from the approved NDCTP. See "Nuclear Decommissioning" above for further discussion.

Table of Contents

Purchased-Power under CDWR Contracts

From January 17, 2001 to December 31, 2002, the CDWR signed long-term contracts that provide power for SCE's customers. SCE acts as a billing agent for the long-term contracts procured by the CDWR. Power purchased by the CDWR under these contracts for delivery to SCE's customers is not considered a cost to SCE.

Receivables

SCE records an allowance for uncollectible accounts, generally determined by the average percentage of amounts written-off in prior periods. SCE assesses its customers a late fee of 0.9% per month, beginning 21 days after the bill is prepared. Inactive accounts are written off after 180 days.

Regulatory Assets and Liabilities

SCE applies authoritative accounting principles for rate-regulated enterprises which applies in circumstances where regulators (in the case of SCE, CPUC and FERC) set rates at levels intended to recover the estimated costs of providing service, plus a return on its net investment, or rate base. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. SCE assesses, at the end of each reporting period, whether regulatory assets are probable of future recovery.

Related Party Transactions

Four EME subsidiaries have 49% to 50% ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. Beginning March 31, 2004, Edison International began consolidating these projects. See Note 14 for further information regarding VIEs.

An indirect wholly owned affiliate of EME has entered into operation and maintenance agreements with partnerships in which EME has a 50% or less ownership interest. EME recorded power generation revenue under these agreements of $26 million in 2009, $28 million in 2008 and $30 million in 2007. EME's accounts receivable with this affiliate totaled $6 million and $7 million at December 31, 2009 and 2008, respectively.

Restricted Cash and Deposits

Cash balances that are restricted under margining agreements are classified as restricted cash and included in current assets, as such amounts change frequently based on forward market prices. Restricted deposits consist of cash balances that are restricted to pay amounts required for lease payments or to provide collateral.

Table of Contents

Revenue Recognition

Electric utility revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each reporting period. Rates charged to customers are based on CPUC-authorized and FERC-approved revenue requirements. CPUC rates are implemented upon final approval. FERC rates are often implemented on an interim basis at the time when the rate change is filed. Revenue collected prior to a final FERC approval decision is subject to refund.

SCE recognizes revenue from base rates and cost-recovery rates, and could potentially recognize revenue or incur penalties under incentive mechanisms. Base rate activities provide for recovery of operation and maintenance costs, capital-related carrying costs and a return or profit, on a forecast basis, as well as a return on certain capital-related projects approved through balancing account mechanisms, separate from the GRC process. Cost-recovery rates provide for recovery for fuel, purchased power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses, and depreciation expense related to certain projects. There is no markup for return or profit for cost-recovery expenses (revenue recognized under cost-recovery rates is equal to expenses incurred under these mechanisms), except for a return on certain capital-related balancing account projects.

The CPUC-authorized decoupling revenue mechanism allows for differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers therefore such differences do not impact electric utility revenue. Differences between authorized operating costs included in SCE's base rate revenue requirement and actual operating costs incurred, other than pass-through costs, do not impact electric utility revenue, but have an impact on earnings.

Power purchased by the CDWR related to long-term contracts it executed on behalf of SCE's customers between January 17, 2001 and December 31, 2002 is not considered a cost to SCE because SCE is acting as an agent for these transactions. Furthermore, amounts billed to ($1.8 billion in 2009, $2.2 billion in 2008 and $2.3 billion in 2007) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and a portion of direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as electric utility revenue by SCE.

Generally, competitive power generation revenue is recorded as electricity is generated or services are provided unless the transaction is accounted for as a derivative and does not qualify for the normal purchases and sales exception. EME's subsidiaries enter into power and fuel hedging, optimization transactions and energy trading contracts, all subject to market conditions. One of EME's subsidiaries executes these transactions primarily through the use of physical forward commodity purchases and sales and financial commodity swaps and options. With respect to its physical forward contracts, EME's subsidiaries generally act as the principal, take title to the commodities, and assume the risks and rewards of ownership. Therefore, EME's subsidiaries record settlement of nontrading physical forward contracts on a gross basis. EME nets the cost of purchased power against related third party sales in markets that use locational marginal pricing, currently PJM. Financial swap and option transactions are settled net and, accordingly, EME's subsidiaries do not take title to the underlying commodity. Therefore, gains and losses from settlement of financial swaps and options are recorded net in competitive power generation revenue. Risks managed include commodity price risk associated with fuel purchases and power sales. In addition, competitive power generation revenue includes revenue under certain long-term power sales contracts which is recognized based on the output delivered at the lower of the amount billable or the average rate over the contract term. The excess of the amounts billed over the portion recorded as competitive power generation revenue is reflected in the caption "Other deferred credits and other long-term liabilities" on the consolidated balance sheets.

EME accounts for grant income on the deferred method and, accordingly, will recognize operating revenues related to such income over the estimated useful life of the projects. At December 31, 2009, EME had $92 million in U.S. Treasury grants receivable with respect to Phase II of the Goat Wind and High Lonesome wind projects included in "Receivables" on the consolidated balance sheets.

Financial services and other revenue are generally derived from leveraged leases, which are recorded by recognizing income over the term of the lease so as to produce a constant rate of return based on the investment leased.

Gains and losses from sale of assets are recognized at the time of the transaction.

Sales and Use Taxes

SCE bills certain sales and use taxes levied by state or local governments to its customers. Included in these sales and use taxes are franchise fees, which SCE pays to various municipalities (based on contracts with these municipalities) in order to operate within the limits of the municipality. SCE bills these franchise fees to its customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SCE's ability to collect from the customer, are accounted for on a gross basis and reflected in electric utility revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as electric utility revenue were $102 million, $103 million and $104 million for the years ended December 31, 2009, 2008 and 2007, respectively. When SCE acts as an agent and when the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are being remitted to the taxing authorities and are not recognized as electric utility revenue.

Stock-Based Compensation

Stock options, performance shares, deferred stock units and, beginning in 2007, restricted stock units have been granted under Edison International's long-term incentive compensation programs. Edison International usually does not issue new common stock for equity awards settled. Rather, a third party is used to facilitate the exercise of stock options and the purchase and delivery of outstanding common stock for settlement of option exercises, performance shares, and restricted stock units. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Deferred stock units

Table of Contents

granted to management are settled in cash, not stock and represent a liability. Restricted stock units are settled in common stock; however, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

Edison International adopted fair value accounting for stock-based compensation on a prospective basis beginning in the first quarter of 2006. Fair value accounting is applied to any unvested awards outstanding as of January 1, 2006 and to all awards granted thereafter. Fair value accounting for stock-based compensation results in the recognition of expense for all stock-based compensation awards.

Edison International recognizes stock-based compensation expense on a straight-line basis over the requisite service period. Edison International recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, Edison International recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006 to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation will be recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement.

Note 2. Derivative Instruments and Hedging Activities

Electric Utility

SCE uses derivative financial instruments to manage financial exposure on its investments and fluctuations in commodity prices and interest rates. SCE manages these risks in part by entering into interest rate swap, cap and lock agreements, and forward commodity transactions, including options, swaps and futures. SCE is exposed to credit loss in the event of nonperformance by counterparties. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Commodity Price Risk

SCE is exposed to commodity price risk which represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's hedging program reduces ratepayer exposure to variability in market prices related to SCE's power and gas activities. SCE recovers its related hedging costs through the ERRA balancing account and as a result, exposure to commodity price is not expected to impact earnings, but may impact cash flows.

SCE's electricity price exposure arises from energy produced and sold in the MRTU market as a result of differences between SCE's load requirements versus the amount of energy delivered from its generating facilities, existing bilateral contracts and CDWR contracts allocated to SCE.

Table of Contents

Approximately 37% of SCE's purchased power supply is subject to natural gas price volatility. SCE's natural gas price exposure arises from purchasing natural gas for generation at Mountainview and peaker plants, from bilateral contracts where pricing is based on natural gas prices (this includes contract energy prices for most renewable QFs which are based on the monthly index price of natural gas delivered at the southern California border), and power contracts in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements.

Natural Gas and Electricity Price Risk

SCE's hedging program reduces ratepayer exposure to variability in market prices. As part of this program, SCE enters into energy options, swaps, forward arrangements, tolling arrangements, and congestion revenue rights (CRRs). These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. In addition, SCE's risk management committee regularly reviews and evaluates exposure and approves transactions.

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging activities at December 31, 2009:

Commodity	**Unit of Measure**	**Economic Hedges**
Electricity options, swaps and forward arrangements	MWh	14,868,034
Natural gas options, swaps and forward arrangements	Bcf	266
Congestion revenue rights[1]	MWh	195,367,422
Tolling arrangements[2]	MWh	116,398,216

1 In September 2007 and November 2008, the CAISO allocated CRRs for the period April 2009 through December 2017 based on SCE's load requirements. In addition, SCE participated in CAISO auctions for the procurement of additional CRRs. These CRRs meet the definition of a derivative.

2 In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced agreements with different project developers who have agreed to construct new southern California generating resources. SCE has entered into a number of contracts, of which five received regulatory approval in the fourth quarter of 2008 and are recorded as derivative instruments. The contracts provide for fixed capacity payments as well as pricing for energy delivered based on a heat rate and contractual operation and maintenance prices. However, due to uncertainty regarding the availability of required emission credits, some of the generating resources may not be constructed and the contracts associated with these resources could therefore terminate, at which time SCE would no longer account for these contracts as derivatives.

Table of Contents

Fair Value of Derivative Instruments

The following table summarizes the gross and net fair values of commodity derivative instruments at December 31, 2009:

	Derivative Assets			Derivative Liabilities			
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	Net Liability
Non-trading activities							
Economic hedges	$ 160	$ 187	$ 347	$ 102	$ 496	$ 598	$ 251
Netting and collateral							
Total	$ 160	$ 187	$ 347	$ 102	$ 496	$ 598	$ 251

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased-power expense and recovers these costs from ratepayers. As a result, realized gains and losses do not affect earnings, but may temporarily affect cash flows. Due to expected future recovery from ratepayers, unrealized gains and losses are deferred and are not recognized as purchased-power expense and therefore do not affect earnings. The results of derivative activities and related regulatory offsets are recorded in cash flows from operating activities in the consolidated statements of cash flows.

The following table summarizes the components of economic hedging activity:

	Years end December 31,		
(in millions)	2009	2008	2007
Realized gains/(losses)	$ (344)	$ (60)	$ (132)
Unrealized gains/(losses)	470	(638)	94

Contingent Features/Credit Related Exposure

Certain derivative instruments and power procurement contracts under SCE's power and natural gas hedging activities contain collateral requirements. SCE has historically provided collateral in the form of cash and/or letters of credit for the benefit of counterparties. These requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments, and other factors.

Certain of these power contracts contain a provision that requires SCE to maintain an investment grade credit rating from each of the major credit rating agencies, referred to as a "credit-risk-related contingent feature." If SCE's credit rating were to fall below investment grade, SCE may be required to pay the derivative liability or post additional collateral. The aggregate fair value of all derivative liabilities with these credit-risk-related contingent features as of December 31, 2009, was $91 million, for which SCE has posted no collateral to its

Table of Contents

counterparties. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, SCE would be required to post $4 million of collateral.

Competitive Power Generation

EME uses derivative instruments to reduce EME's exposure to market risks that arise from fluctuations in prices of electricity, capacity, fuel, emission allowances, and transmission rights. Additionally, EME's financial results can be affected by fluctuations in interest rates. To the extent that EME does not use derivative instruments to hedge these market risks, the unhedged portions will be subject to the risks and benefits of spot market price movements. Hedge transactions are primarily entered into using derivative instruments including:

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

The extent to which EME hedges its market price risk depends on several factors. First, EME evaluates over-the-counter market prices to determine if forward market prices are sufficiently attractive compared to the risks associated with the fluctuating spot market. Second, EME evaluates the sufficiency of its credit capacity at EME and Midwest Generation and whether the forward sales markets have sufficient liquidity to enable EME to identify appropriate counterparties for hedge transactions.

Many of the derivative instruments entered into for risk management purposes (also referred to as non-trading purposes) meet the requirements for hedge accounting. However, not all derivative instruments entered into for risk management purposes will qualify for hedge accounting treatment. Furthermore, EME utilizes derivative contracts to adjust financial and/or physical positions that reduce costs or increase gross margin. Accordingly, risk management positions may not be designated as cash flow hedges and are thus marked to market through current period earnings (derivatives that are entered into for risk management, but which are not designated as cash flow hedges, are referred to as economic hedges).

Authoritative guidance on derivatives and hedging affects the timing of income recognition, but has no effect on cash flow. To the extent that income varies from accrual accounting (i.e., revenue recognition based on the settlement of transactions), EME records unrealized gains or losses. EME classifies unrealized gains and losses from commodity contracts in operating revenues or fuel expenses based on the item being hedged. In addition, the results of derivative activities are recorded in cash flows from operating activities in the consolidated statements of cash flows.

Table of Contents

Derivative instruments that are utilized for trading purposes are measured at fair value and included in the balance sheet as derivative assets or liabilities. In the absence of quoted market prices, derivative instruments are valued at fair value as determined through the methodology outlined in Note 10 Fair Value Measurements. Resulting gains and losses are recognized in operating revenues in the accompanying consolidated statements of income in the period of change.

Where EME's derivative instruments are subject to a master netting agreement and the criteria of authoritative guidance are met, EME presents its derivative assets and liabilities on a net basis on its consolidated balance sheet.

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging and trading activities at December 31, 2009:

				Hedging Activities		
Commodity	**Instrument**	**Classification**	**Unit of Measure**	**Cash Flow Hedges**	**Economic Hedges**	**Trading Activities**
Electricity	Forwards/Futures	Sales	GWh	24,355[1]	26,838[3]	23,306
Electricity	Forwards/Futures	Purchases	GWh	106[1]	25,971[3]	23,404
Electricity	Capacity	Sales	MW-Day (in thousands)	254[2]	1[2]	597[2]
Electricity	Capacity	Purchases	MW-Day (in thousands)	11[2]	2[2]	736[2]
Electricity	Congestion	Sales	GWh		136[4]	10,212[4]
Electricity	Congestion	Purchases	GWh		1,576[4]	181,930[4]
Natural gas	Forwards/Futures	Sales	billion cubic feet		3.3	30.8
Natural gas	Forwards/Futures	Purchases	billion cubic feet			30.6
Fuel oil	Forwards/Futures	Sales	Barrels		250,000	120,000
Fuel oil	Forwards/Futures	Purchases	Barrels		625,000	120,000

1 EME's hedge products include forward and futures contracts that qualify for hedge accounting. This category excludes power contracts for the Midwest Generation Plants which meet the normal sales and purchase exception and are accounted for on the accrual method.

2 EME's hedge transactions for capacity result from bilateral trades. Capacity sold in the PJM RPM auction is not accounted for as a derivative.

3 EME also entered into transactions that adjust financial and physical positions, or day-ahead and real-time positions to reduce costs or increase gross margin. These positions largely offset each other. The net sales positions of these categories are primarily related to hedge transactions that are not designated as cash flow hedges.

4 Congestion contracts include financial transmission rights, transmission congestion contracts or congestion revenue rights. These positions are similar to a swap, where the buyer is entitled to receive a stream of revenues (or charges) based on the hourly day-ahead price differences between two locations.

Table of Contents

Included in trading activities in the preceding table, EME shows net the volume of energy trading activities that are physically settled. Gross purchases and sales totaled 3,791 GWh, 4,080 GWh and 4,130 GWh during 2009, 2008 and 2007, respectively.

Interest Rate Swaps

Viento Funding II, Inc., an EME subsidiary, in conjunction with its wind financing, entered into seven-year amortizing interest rate swaps accounted for as cash flow hedges with a total notional amount of approximately $160 million at December 31, 2009. The interest rate swaps entitle Viento Funding II to receive a floating (six-month LIBOR) rate and pay a fixed rate of 3.175%. The interest rate swap agreements expire in June 2016.

Fair Value of Derivative Instruments

The following table summarizes the gross fair value of derivative instruments at December 31, 2009:

	Derivative Assets			Derivative Liabilities			Net
(in millions)	Short-term	Long-term	Subtotal	Short-term	Long-term	Subtotal	Assets
Non-trading activities							
Cash flow hedges	$ 240	$ 17	$ 257	$ 69	$ 6	$ 75	$ 182
Economic hedges	202	8	210	180		180	30
Trading activities	234	111	345	182	41	223	122
	$ 676	$ 136	$ 812	$ 431	$ 47	$ 478	$ 334
Netting and collateral received	(479)	(55)	(534)	(426)	(32)	(458)	(76)
Total	$ 197	$ 81	$ 278	$ 5	$ 15	$ 20	$ 258

Income Statement Impact of Derivative Instruments

The following table provides the activity of accumulated other comprehensive income for the year ended December 31, 2009, containing the information about the changes in the fair value of cash flow hedges and reclassification from accumulated other comprehensive income into results of operations:

(in millions)	Cash Flow Hedge Activity[1]	Income Statement Location
Accumulated other comprehensive income derivative gain at December 31, 2008	$ 398	
Effective portion of changes in fair value	79	
Reclassification from accumulated other comprehensive income to net income	(302)	Operating revenue
Accumulated other comprehensive income derivative gain at December 31, 2009	$ 175	

1

Unrealized derivative gains are before income taxes. The after-tax amounts recorded in accumulated other comprehensive income at December 31, 2009 and 2008 were $105 million and $240 million, respectively.

Table of Contents

The portion of a cash flow hedge that does not offset the change in the 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 $24 million, $7 million and $(41) million in 2009, 2008 and 2007, respectively, representing the amount of cash flow hedge ineffectiveness and are reflected in operating revenues on the consolidated statements of income.

The effect of realized and unrealized gains (losses) from derivative instruments used for economic hedging and trading purposes on the consolidated statements of income for the year ended December 31, 2009 is presented below:

(in millions)	**Income Statement Location**	**December 31, 2009**
Economic hedges	Operating revenue	$ 34
	Fuel expense	18
Trading activities	Operating revenue	47

Contingent Features/Credit Related Exposure

Certain derivative instruments contain margin and collateral deposit requirements. Since EME's credit ratings are below investment grade, EME has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties related to the net of accounts payable, accounts receivable, unrealized losses and unrealized gains in connection with derivative activities. Certain derivative contracts do not require margin, but contain provisions that require EME or Midwest Generation to comply with the terms and conditions of their respective credit facilities. The credit facilities each contain financial covenants. Some hedge contracts include provisions related 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 may 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 margin, but provide that each party can 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 all derivative instruments with credit-risk-related contingent features is in an asset position on December 31, 2009 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 additional collateral postings under the contingent features described above.

Table of Contents

Note 3. Liabilities and Lines of Credit

Long-Term Debt

The following table summarizes long-term debt (rates and terms are as of December 31, 2009):

	December 31,	
(in millions)	**2009**	**2008**
First and refunding mortgage bonds:		
2014 2039 (4.15% to 6.05% and variable)	$ 5,475	$ 4,875
Pollution-control bonds:		
2015 2035 (2.9% to 5.55% and variable)	1,196	1,196
Bonds repurchased	(468)	(249)
Debentures and notes:		
2010 2053 (noninterest-bearing to 8.75%)	4,631	5,320
Long-term debt due within one year	(377)	(174)
Unamortized debt discount net	(20)	(18)
Total	$ 10,437	$ 10,950

Long-term debt maturities and sinking-fund requirements for the next five years are: 2010 $377 million; 2011 $36 million; 2012 $40 million; 2013 $545 million; and 2014 $1.1 billion.

In January 2010, Edison Capital redeemed in full its medium-term loans. The balance of these loans was $89 million at December 31, 2009.

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from certain pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2009, SCE was in compliance with this debt covenant. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

In late 2007 and early 2008, SCE purchased in the secondary market its auction rate bonds, totaling $249 million, and converted the issue from an auction-based reset process to a variable rate structure. In 2009, SCE purchased two issues of its tax-exempt bonds totaling $219 million that were subject to remarketing and also converted those issues to a variable rate structure. SCE continues to hold these bonds which remain outstanding and have not been retired or cancelled.

EME Senior Notes

EME has $3.7 billion of senior notes due 2013 through 2027. The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, of the senior notes plus a

Table of Contents

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

EME recorded a total pre-tax loss of $160 million ($98 million after tax) on early extinguishment of debt in 2007 related to the early repayment of EME's 7.73% senior notes due June 15, 2009 and Midwest Generation's 8.75% second priority senior secured notes due May 1, 2034.

Short-Term Debt

SCE short-term debt is generally used to finance fuel inventories, balancing account under-collections and general, temporary cash requirements including power purchase payments. At December 31, 2009, the outstanding short-term debt was zero. At December 31, 2008, the outstanding short-term debt was $1.89 billion at a weighted-average interest rate of 0.67%. This short-term debt was supported by a $2.5 billion credit line.

Edison International (parent) short-term debt is generally used for liquidity purposes. At December 31, 2009, the outstanding short-term debt was $85 million at a weighted-average interest rate of 0.60%. At December 31, 2008, the outstanding short-term debt was $250 million at a weighted-average interest rate of 0.85%.

Credit Agreements

On March 17, 2009, SCE entered into a new $500 million, 364-day revolving credit facility, terminating on March 16, 2010. The additional liquidity provided by the facility will be used to support SCE's ongoing power procurement-related needs.

In June 2009, SCE amended its $2.5 billion five-year credit facility, reducing the commitment to $2.4 billion, and Edison International amended its $1.5 billion revolving credit facility, reducing the commitment to $1.4 billion. Both amendments were made to remove a subsidiary of Lehman Brothers Holdings as a lender. Each of these credit facilities matures in February 2013 and provides four one-year options to extend by mutual consent.

EME has a $600 million secured credit facility that matures in June 2012. At December 31, 2009, EME had no borrowings outstanding and $101 million of letters of credit outstanding under this credit facility. EME's subsidiary, Midwest Generation, also has a $500 million senior secured working capital facility that matures in June 2012 and provides two one-year options to extend by mutual consent. As of December 31, 2009, Midwest Generation had no borrowings outstanding and $3 million of letters of credit had been utilized under the working capital facility.

Table of Contents

The following table summarizes the status of the credit facilities at December 31, 2009:

(in millions)	SCE	EMG	Edison International (parent)
Commitment	$ 2,894	$ 1,100	$ 1,426
Less: Commitment from Lehman Brothers subsidiary		(36)	
	2,894	1,064	1,426
Outstanding borrowings			(85)
Outstanding letters of credit	(12)	(104)	
Amount available	$ 2,882	$ 960	$ 1,341

Standby Letters of Credit

As of December 31, 2009, standby letters of credit under EME and its subsidiaries' credit facilities aggregated $119 million and were scheduled to expire as follows: $111 million in 2010 and $8 million in 2011.

Note 4. Income Taxes

The sources of income (loss) before income taxes are:

(in millions)	Years ended December 31, 2009	2008	2007
Domestic	$ 758	$ 1,809	$ 1,570
Foreign		2	22
Income from continuing operations attributable to common shareholders	758	1,811	1,592
Discontinued operations	(7)	5	3
Income attributable to common shareholders	$ 751	$ 1,816	$ 1,595

Table of Contents

The components of income tax expense (benefit) by location of taxing jurisdiction are:

	Years ended December 31,		
(in millions)	**2009**	**2008**	**2007**
Current:			
Federal	$ 1,211	$ 183	$ 359
State	361	80	95
Foreign			
	1,572	263	454
Deferred:			
Federal	(1,638)	307	57
State	(32)	26	(19)
	(1,670)	333	38
Total continuing operations	(98)	596	492
Discontinued operations	(2)	5	5
Total	$ (100)	$ 601	$ 497

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

	December 31,	
(in millions)	**2009**	**2008**
Deferred tax assets:		
Property and software related	$ 692	$ 556
Unrealized gains and losses	322	77
Regulatory balancing accounts	229	436
Decommissioning	173	168
Accrued charges		108
Pension and PBOPs	216	203
Other	827	490
Total	2,459	2,038
Deferred tax liabilities:		
Property-related	5,285	4,079
Leveraged leases	194	2,313
Capitalized software costs	286	231
Regulatory balancing accounts	257	433
Unrealized gains and losses	315	70
Other	453	525
Total	6,790	7,651
Accumulated deferred income tax liability net	$ 4,331	$ 5,613
Classification of accumulated deferred income taxes net:		
Included in total deferred credits and other liabilities	$ 4,334	$ 5,717
Included in current assets	$ 3	$ 104

Table of Contents

The federal statutory income tax rate is reconciled to the effective tax rate from continuing operations attributable to common shareholders, as follows:

	Years ended December 31,		
	2009	2008	2007
Federal statutory rate	35.0%	35.0%	35.0%
State tax net of federal benefit	6.4	4.2	4.1
Property-related	(7.6)	(3.2)	(0.2)
Housing and production credits	(8.4)	(3.1)	(2.9)
Tax reserve adjustments	2.4	0.7	(3.5)
Global tax settlement	(42.5)		
Other	1.8	(0.7)	(1.6)
Effective tax rate	(12.9%)	32.9%	30.9%

The effective tax rate of (12.9%) in 2009 included benefits related to both the Global Settlement and recognition of additional AFUDC equity resulting from the transfer of the Mountainview power plant to utility rate base. Production tax credits increased in 2009 due to growth in EME's wind portfolio. The effective tax rate of 32.9% in 2008 included higher software deductions resulting from the implementation of SAP. The effective tax rate of 30.9% in 2007 includes reductions in liabilities for uncertain tax positions to reflect both the progress made in an administrative appeals 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 CPUC requires flow-through rate-making treatment for the current tax benefit arising from certain property-related and other temporary differences, which reverse over time. The accounting treatment for these temporary differences results in recording regulatory assets and liabilities for amounts that would otherwise be recorded to deferred income tax expense.

Edison International and its subsidiaries had California net operating loss carryforwards with expirations dates beginning in 2010 of $57 million and $59 million at December 31, 2009 and 2008, respectively.

Accounting for Uncertainty in Income Taxes

Authoritative guidance related to accounting for uncertainty in income taxes 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. The guidance requires the disclosure of all unrecognized tax benefits, which includes both the reserves recorded for tax positions on filed tax returns and the unrecognized portion of affirmative claims.

Table of Contents

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits from January 1 to December 31:

(in millions)	2009	2008	2007
Balance at January 1	$ 2,237	$ 2,114	$ 2,160
Tax positions taken during the current year:			
Increases	102	118	69
Tax positions taken during a prior year:			
Increases	201	162	125
Decreases	(224)	(157)	(230)
Decreases for settlements during the period	(1,652)		(10)
Balance at December 31	$ 664	$ 2,237	$ 2,114

Unrecognized tax benefits were reduced by $1.7 billion during 2009 primarily due to consummation of the Global Settlement as discussed below.

Edison International believes it is reasonably possible that unrecognized tax benefits could be reduced by up to $90 million within the next twelve months from a settlement of state tax matters for periods through 2002.

As of December 31, 2009 and 2008, respectively, if recognized, $374 million and $210 million of the unrecognized tax benefits would impact the effective tax rate.

Accrued Interest and Penalties

The total amount of accrued interest and penalty related to Edison International's income tax liabilities was $380 million and $200 million as of December 31, 2009 and 2008, respectively. The after-tax interest expense (income) recognized and included in income tax expense was $(80) million, $23 million and $(12) million in 2009, 2008 and 2007, respectively.

Tax Years Subject to Examination

Edison International's federal income tax returns are currently under active examination by the IRS for tax years 2003 through 2006 and are subject to examination through tax years 2008.

Edison International's California and other state income tax returns are open for examination by the California Franchise Tax Board and other state tax authorities for tax years 1986 through 2008. The Franchise Tax Board is currently examining tax years through 2006.

Global Settlement

Edison International and the IRS finalized the terms of a Global Settlement on May 5, 2009. The Global Settlement resolves federal tax disputes related to Edison Capital's cross-border, leveraged leases through 2009, and all other outstanding federal tax disputes and affirmative claims for tax years 1986 through 2002. Pursuant to the Global Settlement, Edison Capital terminated its interests in the cross-border leases and received net proceeds of $1.385 billion in 2009. See Note 18 for further discussion of the termination of the cross-border leases.

The Global Settlement and termination of the Edison Capital cross-border leases resulted in the following impacts:

Edison International recorded a consolidated after-tax earnings charge of $254 million in 2009 and expects that the Global Settlement together with the termination of the Edison Capital cross-border leases will result in a positive cash impact over time of approximately $400 million. The cash impacts of the Global Settlement will occur over the next few years.

The Global Settlement and related lease terminations resulted in a loss of $614 million, after tax, for Edison Capital through the second quarter of 2009, reflected in "Lease termination and other" ($920 million pre-tax), and "Income tax expense (benefit)" on the consolidated statements of income. Edison Capital's overall net cash outflow from the Global Settlement will be approximately $286 million over time.

The Global Settlement also resolves all of SCE's federal income tax disputes and affirmative claims through tax year 2002. During 2009 SCE recorded after-tax earnings of approximately $306 million, reflected in "Income tax expense (benefit)" on the consolidated statements of income, primarily related to settlement of two affirmative claims associated with: (1) the taxation of balancing account over-collections; and (2) taxation of proceeds received in consideration for transferring control of SCE's transmission system to the CAISO and allowing direct access to SCE's distribution system, which were mandated as part of California's deregulation process. Both claims created positive tax timing differences that resulted in an interest refund from the IRS for prior period tax overpayments, but did not result in a permanent reduction in SCE's income tax liability. SCE expects an overall positive cash impact resulting from the Global Settlement of approximately $646 million over time, including the cash benefit of prior tax deposits of approximately $200 million.

On a combined basis, all other federal tax disputes involving the Edison International consolidated group for tax years 1986 - 2002 resulted in after-tax earnings of $54 million and expected positive cash flow over time of approximately $40 million. The earnings are attributable to miscellaneous net income tax benefits arising from the Global Settlement.

Edison International is currently addressing the impacts of the Global Settlement with state tax authorities. Resolution of such matters with such authorities may change the estimated cash and earnings impacts described above.

Note 5. Compensation and Benefit Plans

Employee Savings Plan

Edison International has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $83 million in 2009, $80 million in 2008 and $73 million in 2007.

Table of Contents

Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

Noncontributory defined benefit pension plans (some with cash balance features) cover most employees meeting minimum service requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking. The expected contributions (all by the employer) are approximately $108 million for the year ending December 31, 2010.

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 (reflecting investment returns, contributions and benefit payments) within the plan trusts declined 35% during 2008. This reduction in the value of plan assets resulted in a change in the pension plan funding status from overfunded to underfunded and will also result in increased future expense and increased future contributions. Improved market conditions in 2009 partially offset the impacts of the 2008 market conditions.

Changes in the plan's funded status also affect the assets and liabilities recorded on the consolidated balance sheets. 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 restricts plans underfunded by more than 20% from providing lump-sum distributions and adopting amendments that increase plan liabilities.

Table of Contents

Information on plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31, 2009	2008
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 3,439	$ 3,355
Service cost	124	120
Interest cost	207	199
Amendments	21	
Actuarial loss	80	3
Benefits paid	(183)	(238)
Projected benefit obligation at end of year	$ 3,688	$ 3,439
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,340	$ 3,597
Actual return (loss) on plan assets	577	(1,105)
Employer contributions	123	86
Benefits paid	(183)	(238)
Fair value of plan assets at end of year	$ 2,857	$ 2,340
Funded status at end of year	$ (831)	$ (1,099)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$ (10)	$ (9)
Long-term liabilities	(821)	(1,090)
	$ (831)	$ (1,099)
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	$ 2	$ 2
Net loss	96	91
	$ 98	$ 93
Amounts recognized as a regulatory asset (liability):		
Prior service cost	$ 42	$ 33
Net loss	556	951
	$ 598	$ 984
Total not yet recognized as expense	$ 696	$ 1,077
Accumulated benefit obligation at end of year	$ 3,342	$ 3,129
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 3,688	$ 3,439
Accumulated benefit obligation	3,342	3,129
Fair value of plan assets	2,857	2,340
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	6.0%	6.25%
Rate of compensation increase	5.0%	5.0%

Table of Contents

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years ended December 31, 2009	2008	2007
Service cost	$ 124	$ 120	$ 117
Interest cost	207	199	185
Expected return on plan assets	(169)	(259)	(245)
Special termination benefits			2
Amortization of prior service cost	11	17	17
Amortization of net loss	61	5	6
Expense under accounting standards	234	82	82
Regulatory adjustment deferred	(94)	(4)	(3)
Total expense recognized	$ 140	$ 78	$ 79

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

(in millions)	Years ended December 31, 2009	2008	2007
Net loss	$ 17	$ 59	$
Amortization of prior service cost	(1)	(1)	(1)
Amortization of net loss	(11)	(5)	(6)
Total recognized in other comprehensive (income) loss	$ 5	$ 53	$ (7)
Total recognized in expense and other comprehensive income	$ 145	$ 131	$ 72

In accordance with authoritative guidance for rate-regulated enterprises, Edison International records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of SCE's postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost that will be amortized to expense in 2010 are $29 million and $8 million, respectively, including $11 million and $1 million, respectively, expected to be reclassified from accumulated other comprehensive income.

The following are weighted-average assumptions used to determine expense:

	Years ended December 31, 2009	2008	2007
Discount rate	6.25%	6.25%	5.75%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected long-term return on plan assets	7.5%	7.5%	7.5%

Table of Contents

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

(in millions)	Years ended December 31,
2010	$ 249
2011	261
2012	274
2013	284
2014	293
2015 2019	1,598

Postretirement Benefits Other Than Pensions

Most non-union employees retiring at or after age 55 with at least 10 years of service may be eligible for postretirement medical, dental, vision and life insurance and other benefits. Eligibility for a company contribution toward the cost of these benefits in retirement depends on a number of factors, including the employee's hire date. The expected contributions (all by the employer) to the PBOP trust are $45 million for the year ending December 31, 2010.

Volatile market conditions have affected the value of Edison International's trusts established to fund its future other postretirement benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trust declined 33% during 2008. This reduction in the value of plan assets resulted in an increase in the plan's underfunded status and will also result in increased future expense and increased future contributions. Improved marked conditions in 2009 partially offset the impacts of the 2008 market conditions.

Changes in the plan's funded status affect the assets and liabilities recorded on Edison International's balance sheets. 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.

Table of Contents

Information on plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31, 2009	2008
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,351	$ 2,271
Service cost	30	41
Interest cost	122	136
Amendments	(65)	3
Actuarial gain	(242)	(20)
Plan participants' contributions	15	11
Medicare Part D subsidy received	5	5
Benefits paid	(106)	(96)
Benefit obligation at end of year	$ 2,110	$ 2,351
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,212	$ 1,816
Actual return (loss) on assets	257	(557)
Employer contributions	76	33
Plan participants' contributions	15	11
Medicare Part D subsidy received	5	5
Benefits paid	(106)	(96)
Fair value of plan assets at end of year	$ 1,459	$ 1,212
Funded status at end of year	$ (651)	$ (1,139)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$ (18)	$ (20)
Long-term liabilities	(633)	(1,119)
	$ (651)	$ (1,139)
Amounts recognized in accumulated other comprehensive loss (income) consist of:		
Prior service cost (credit)	$ (5)	$ (4)
Net loss	15	24
	$ 10	$ 20
Amounts recognized as a regulatory asset (liability):		
Prior service cost (credit)	$ (209)	$ (178)
Net loss	625	1,076
	$ 416	$ 898
Total not yet recognized as expense	$ 426	$ 918
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	6.0%	6.25%
Assumed health care cost trend rates:		
Rate assumed for following year	8.25%	8.75%
Ultimate rate	5.5%	5.5%
Year ultimate rate reached	2016	2016

186

Table of Contents

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years ended December 31, 2009	2008	2007
Service cost	$ 30	$ 41	$ 45
Interest cost	122	136	130
Expected return on plan assets	(81)	(123)	(118)
Special termination benefits			1
Amortization of prior service cost (credit)	(34)	(31)	(31)
Amortization of net loss	45	16	30
Total expense	$ 82	$ 39	$ 57

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

(in millions)	Years ended December 31, 2009	2008	2007
Net loss (gain)	$ (8)	$ 6	$ 3
Prior service cost	(3)	3	
Amortization of prior service cost (credit)	2	2	2
Amortization of net loss	(1)	(2)	(2)
Total recognized in other comprehensive income	$ (10)	$ 9	$ 3
Total recognized in expense and other comprehensive income	$ 72	$ 48	$ 60

In accordance with authoritative guidance for rate-regulated enterprises, Edison International records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of SCE's postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost (credit) that will be amortized to expense in 2010 are $32 million and $(38) million, respectively including $1 million and $(2) million respectively, expected to be reclassified from accumulated other comprehensive income.

The following are weighted-average assumptions used to determine expense:

	Years ended December 31, 2009	2008	2007
Discount rate	6.25%	6.25%	5.75%
Expected long-term return on plan assets	7.0%	7.0%	7.0%
Assumed health care cost trend rates:			
Current year	8.75%	9.25%	9.25%
Ultimate rate	5.5%	5.0%	5.0%
Year ultimate rate reached	2016	2015	2015

Table of Contents

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2009 by $226 million and annual aggregate service and interest costs by $15 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2009 by $206 million and annual aggregate service and interest costs by $14 million. The following are benefit payments expected to be paid:

	Year ending December 31,	
(in millions)	**Before Subsidy***	**Net**
2010	$ 97	$ 92
2011	104	98
2012	112	105
2013	119	112
2014	127	119
2015 2019	753	700

* Medicare Part D prescription drug benefits

Plan Assets

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. In 2009, the trusts' investment committee approved changes in target asset allocations. Target allocations for pension plan assets are 34% for U.S. equities, 17% for non-U.S. equities, 9% for alternative investments and 40% fixed income. Target allocation for PBOP plan assets are 45% U.S. equities, 14% non-U.S. equities, 2% private equities and 39% fixed income. Edison International employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is managed through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. Edison International also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States Equities: Common and preferred stocks of large, medium and small companies which are predominantly United States-based.

Non-United States Equities: Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.

Alternative Investments:

Private Equities: Limited partnerships that invest in non-publicly traded entities. The pension and PBOP target allocations are 6% and 2%, respectively.

Hedge funds: Funds that have target return and risk characteristics that are diversified among global equity, fixed income and currency markets. There is no systematic exposure to any market and investments are made in liquid instruments according to relative opportunities within and across markets. The pension target allocation is 3%.

Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities including municipal bonds, mortgage backed securities and corporate debt obligations. A small portion of the fixed income positions may be held in debt securities that are below investment grade.

Asset class portfolio weights are permitted to range within plus or minus 3%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to reallocate portfolio cash positions. Where authorized, a few of the plan's investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets

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

Capital Markets Return Forecasts

Capital markets return forecasts are based on long-term strategic planning assumptions from an independent firm which uses its research, modeling and judgment to forecast rates of return for global asset classes. In addition, a separate analysis of expected returns is conducted. The estimated total return for fixed income is based on historic long-term United States government bonds data. The estimated total return for intermediate United States government bonds is based on historic and projected data. The estimated rate of return for U.S. and non-U.S. equity includes a 3% premium over the estimated total return for intermediate United States government bonds. The rate of return for private equity and hedge funds is estimated to be a 3% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Fair Value of Plan Assets

The PBOP Plan and the Southern California Edison Company Retirement Plan Trust (Master Trust) assets include investments in equity securities, U.S. treasury securities, other fixed-income securities, common/collective funds, mutual funds, other investment entities, foreign exchange and interest rate contracts, and partnership/joint ventures. Equity securities, U.S. treasury securities, mutual and money market funds are classified as Level 1 as fair value is determined by observable, unadjusted quoted market prices in active or highly liquid and transparent markets. Common/collective funds are valued at the net asset value (NAV) of shares held. Although common/collective funds are determined by observable prices, they are classified as Level 2 because they trade in markets that are less active and transparent. The

Table of Contents

fair value of the underlying investments in equity mutual funds and equity common/collective funds are based upon stock-exchange prices. The fair value of the underlying investments in fixed-income common/collective funds, fixed-income mutual funds and other fixed income securities including municipal bonds are 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. Foreign exchange and interest rate contracts are classified as Level 2 because the values are based on observable prices but are not traded on an exchange. Future contracts trade on an exchange and therefore classified as Level 1. One of the partnerships is classified as Level 2 since this investment can be readily redeemed at NAV and the underlying investments are liquid publicly traded fixed-income securities which have observable prices. The remaining partnerships/joint ventures are classified as Level 3 because fair value is determined primarily based upon management estimates of future cash flows. Other investment entities are valued similarly to common collective funds and are therefore classified as Level 2. Substantially all of the registered investment companies are either mutual or money market funds and are therefore classified as Level 1 for the reasons noted above. The remaining fund in this category is readily redeemable at NAV and classified as Level 2 and is discussed further at footnote 7 to the pension master trust table.

Table of Contents

Pension Plan

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2009 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks[1]	$ 678	$	$	$ 678
Common/collective funds[2]		612		612
Corporate bonds[3]		469		469
U.S. government and agency securities[4]	104	352		456
Partnerships/joint ventures[5]		101	240	341
Other investment entities[6]		135		135
Registered investment companies[7]	73	58		131
Interest-bearing cash	5			5
Foreign exchange contracts		6		6
Other		7		7
Total	$ 860	$ 1,740	$ 240	$ 2,840
Receivables and payables, net				17
Net plan assets available for benefits				$ 2,857

1 Corporate stocks are diversified. Performance is primarily benchmarked against the Russell Indexes (61%) and Morgan Stanley Capital International (MSCI) index (39%).

2 At December 31, 2009, 69% of the common/collective assets were invested in equity index funds that seek to track performance of the Standard and Poor's (S&P 500) Index (33%), Russell 200 and Russell 1000 indexes (26%) and the Morgan Stanley Capital International Europe, Australasia and Far East (EAFE) Index (10%). A non index fund representing 20% of this category as of December 31, 2009, invests in equity securities the Trustee believes are undervalued. Another fund representing 7% of this category is a global hedge fund that invests in short-term fixed income securities and seeks to exceed the performance of the Citigroup One-Month U.S. Treasury Bill Index.

3 Corporate bonds are diversified. At December 31, 2009, this category includes $52 million for collateralized mortgage obligations and other asset backed securities of which $12 million are below investment grade.

4 Level 1 U.S. government and agency securities are U.S. treasury bonds and notes. Level 2 primarily relates to the Federal Home Loan Mortgage Corporation and the Federal National Mortgage Association.

5 Partnerships/joint venture Level 2 consists of a partnership which invests in publicly traded fixed income securities, primarily from the banking and finance industry and U.S. government agencies. Approximately 60% of the Level 3 partnerships are invested in asset backed securities including distressed mortgages. The remaining Level 3 partnerships are invested in several small private equity and venture capital funds. Investment strategies for these funds include branded consumer products, early stage technology, California geographic focus, and diversified US and non-US fund-of-funds.

6 At December 31, 2009, 64% of the other investment entity balance is invested in emerging market equity securities. About 17% of the assets in this category are invested in domestic mortgage backed securities. Most of the remaining funds invest in below grade fixed-income securities including foreign issuers.

7

At December 31, 2009, Level 1 of registered investment companies consists of a global equity mutual fund which seeks to outperform the Morgan Stanley Capital International Inc. World Total Return Index. Level 2 of this category is a is a hedge fund that invests through liquid instruments in a global diversified portfolio of equity, fixed income, interest rate, foreign currency and commodities markets.

At December 31, 2009, approximately 67% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

Table of Contents

The following table sets forth a summary of changes in the fair value of Level 3 investments for the year ended December 31, 2009:

(in millions)	2009
Fair value, net at January 1, 2009	$ 111
Actual return on plan assets:	
Relating to assets still held at end of period	34
Relating to assets sold during the period	6
Purchases and dispositions, net	89
Transfers in and /or out of Level 3	
Fair value, net at December 31, 2009	$ 240

Postretirement Benefits Other Than Pensions

The following table sets forth the PBOP Plan's financial assets that were accounted for at fair value as of December 31, 2009 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Common/collective funds[1]	$	$ 648	$	$ 648
Corporate stocks[2]	250			250
Registered investment companies[3]	213			213
Corporate notes and bonds[4]		151		151
U.S. government and agency securities[5]	39	28		67
Partnerships[6]			49	49
Interest bearing cash	14			14
Other[7]	3	74		77
Total	$ 519	$ 901	$ 49	$ 1,469
Receivables and payables, net				(10)
Combined net plan assets available for benefits				$ 1,459

1 At December 31, 2009, 61% of the common/collective assets are invested in a large cap index fund which seeks to track performance of the Russell 1000 index. At December 31, 2009, 23% of the assets in this category are in index funds which seek to track performance in the Morgan Stanley Capital International Europe, Australasia and Far East (EAFE) Index. 7% of this category is invested in a privately managed bond fund and 6% in a fund which invests in equity securities the fund manager believes are undervalued.

2 Corporate stock performance is primarily benchmarked against the Russell Indexes (67%) and the MSCI All Country World (ACWI) index (33%).

3 Registered investment companies consist of a money market fund and an investment grade corporate bond mutual fund.

4 Corporate notes and bonds are diversified and include approximately $10 million for commercial collateralized mortgage obligations and other asset backed securities.

5 Level 1 U.S. government and agency securities are U.S. treasury bonds and notes. Level 2 primarily relates to the Federal Home Loan Mortgage Corporation and the Federal National Mortgage Association.

[6] Approximately 90% of the partnerships category is invested in asset backed securities including distressed mortgages.

[7] Other includes $58 million of municipal securities at December 31, 2009.

Table of Contents

At December 31, 2009, approximately 76% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

The following table sets forth a summary of changes in the fair value of PBOP Level 3 investments for the year ended December 31, 2009:

(in millions)		**2009**
Fair value, net at January 1, 2009	$	12
Actual return on plan assets		
Relating to assets still held at end of period		12
Relating to assets sold during the period		1
Purchases and dispositions, net		27
Transfers in and /or out of Level 3		(3)
Fair value, net at December 31, 2009	$	49

Stock-Based Compensation

On April 26, 2007, Edison International's shareholders approved a new incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. No additional awards were granted under Edison International's prior stock-based compensation plans on or after April 26, 2007, with all subsequent issuances being made under the new plan. The maximum number of shares of Edison International's common stock authorized to be issued or transferred pursuant to awards under the incentive plan as adopted was 8.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued ("carry-over shares"). On April 23, 2009, Edison International's shareholders approved certain amendments to the 2007 Performance Plan increasing such authorization by 13 million shares, resulting in an aggregate share limit of 21.5 million shares, plus the carry-over shares. As of December 31, 2009, Edison International had approximately 13 million shares remaining for future issuance under its stock-based compensation plans.

Total stock-based compensation expense, net of amounts capitalized (reflected in the caption "Operation and maintenance" on the consolidated statements of income) was $33 million, $31 million and $42 million for 2009, 2008 and 2007, respectively. The income tax benefit recognized in the consolidated statements of income was $13 million, $12 million and $17 million for 2009, 2008 and 2007, respectively. Excess tax benefits included in "Stock-based compensation net" in the financing section of the consolidated statements of cash flows were $9 million, $10 million and $45 million in 2009, 2008 and 2007, respectively.

Stock Options

Under various plans, Edison International has granted stock options at exercise prices equal to the average of the high and low price, and beginning in 2007, at the closing price at the grant date. Edison International may grant stock options and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service,

Table of Contents

with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants, as discussed in "Stock-Based Compensation" in Note 1. Stock-based compensation expense associated with stock options was $13 million, $25 million and $25 million for 2009, 2008 and 2007, respectively.

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

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

	Years ended December 31,		
	2009	**2008**	**2007**
Expected terms (in years)	7.4	7.4	7.5
Risk-free interest rate	2.8% 3.5%	2.6% 3.8%	4.6% 4.8%
Expected dividend yield	3.6% 5.0%	2.3% 3.9%	2.1% 2.4%
Weighted-average expected dividend yield	4.9%	2.6%	2.4%
Expected volatility	20% 21%	17% 19%	16% 17%
Weighted-average volatility	20.6%	17.6%	16.5%

The expected term represents the period of time for which the options are expected to be outstanding and is primarily based on historical exercise and post-vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a zero coupon U.S. Treasury issued STRIPS (separate trading of registered interest and principal of securities) whose maturity equals the option's expected term on the measurement date. Expected volatility is based on the historical volatility of Edison International's common stock for the lesser of 1) the period from January 1, 2003 through the last month-end prior to the grant date or 2) the length of the option's expected term. The volatility period used was 84 months, 72 months and 36 months at December 31, 2009, 2008 and 2007, respectively.

Table of Contents

The following is a summary of the status of Edison International stock options:

	Stock options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2008	13,441,835	$ 30.55		
Granted	5,065,405	$ 25.15		
Expired	(174,580)	$ 46.79		
Forfeited	(241,565)	$ 32.45		
Exercised	(723,063)	$ 17.86		
Outstanding at December 31, 2009	17,368,032	$ 32.15	6.47	
Vested and expected to vest at December 31, 2009	16,645,896	$ 32.13	6.38	$ 67,235,305
Exercisable at December 31, 2009	9,470,724	$ 30.87	4.85	$ 44,657,946

The weighted-average grant-date fair value of options granted during 2009, 2008 and 2007 was $3.05, $9.70 and $11.44, respectively. The total intrinsic value of options exercised during 2009, 2008 and 2007 was $12 million, $24 million and $109 million, respectively. At December 31, 2009, there was $21 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 2009, 2008 and 2007 was $14 million, $24 million and $27 million, respectively.

Cash outflows to purchase Edison International shares in the open market to settle stock option exercises were $25 million, $55 million and $195 million for 2009, 2008 and 2007, respectively. Cash inflows from participants to exercise stock options were $13 million, $30 million and $86 million for 2009, 2008 and 2007, respectively. The tax benefit realized from options exercised for 2009, 2008 and 2007 was $5 million, $10 million and $43 million, respectively.

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2007, March 2008 and March 2009 and vest at the end of December 2009, 2010 and 2011, respectively. Performance shares awarded contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's common stock performance relative to the performance of a specified group of peer companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash

Table of Contents

settlement in common stock. Edison International also has discretion to pay certain dividend equivalents in Edison International common stock. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares that can be settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value. Performance share expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants. Stock-based compensation expense (benefit) associated with performance shares was $5 million, $(4) million and $12 million for 2009, 2008 and 2007, respectively.

Cash outflows to purchase Edison International shares in the open market to settle performance shares classified as equity awards were $10 million and $20 million for 2008 and 2007, respectively. There were no performance shares settled in 2009. In 2007, Edison International changed the classification of the cash paid for the settlement of performance shares from common stock to retained earnings to conform with the classification for settlement of stock option exercises. The tax benefit realized from settlement of performance shares classified as equity awards for 2008 and 2007 was $4 million and $8 million, respectively.

The performance shares' fair value is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires a risk-free interest rate and an expected volatility rate assumption. The risk-free interest rate is based on the daily spot rate on the grant or valuation date on U.S. Treasury zero coupon issue or STRIPS (separate trading of registered interest and principal securities) with terms equal to the remaining term of the performance shares and is used as a proxy for the expected return for the specified group of companies. Expected volatility is based on the historical volatility of Edison International's (and the specified group of companies) common stock for the most recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

The risk-free interest rate used to determine the grant date fair values for the 2009, 2008 and 2007 performance shares classified as share-based equity awards was 1.3%, 3.9% and 4.8%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2009, 2008 and 2007 performance shares classified as share-based equity awards was 21.4%, 17.4% and 16.5%, respectively. The portion of performance shares classified as share-based liability awards are revalued at each reporting period. The risk-free interest rate used to determine the fair value as of December 31, 2009 was 1.1% and 0.5%, respectively, for 2009 and 2008 performance shares. The expected volatility rate used to determine the fair value as of December 31, 2009 was 21.9%. The risk-free interest rate used to determine the fair value as of December 31, 2008 was 0.8% and 0.4%, respectively, for 2008 and 2007 performance shares. The expected volatility rate used to determine the fair value as of December 31, 2008 was 19.2%. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2007 was 4.3% and 17.1%, respectively, for 2007 and 2006 performance shares. The total intrinsic value of performance shares settled during

Table of Contents

2008 and 2007 was $22 million and $44 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2008 and 2007 of $8 million and $14 million, respectively. There were no performance shares settled in 2009. At December 31, 2009, there was $1 million (based on the December 31, 2009 fair value of performance shares classified as liability awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of performance shares that vested during 2009, 2008 and 2007 was $1 million, $4 million and $17 million, respectively.

The following is a summary of the status of Edison International nonvested performance shares classified as equity awards:

	Performance Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2008	175,177	$ 49.45
Granted	179,187	$ 21.42
Forfeited	(10,912)	$ 31.04
Paid out		$
Nonvested at December 31, 2009	343,452	$ 35.41

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2009, 2008 and 2007 was $21.42, $45.53 and $57.55, respectively.

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

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2008	175,177	
Granted	179,187	
Forfeited	(10,912)	
Paid out		
Nonvested at December 31, 2009	343,452	$ 17.69

Note 6. Commitments and Contingencies

Lease Commitments

In the ordinary course of business, SCE enters into various agreements to purchase power, resource capacity, and environmental attributes. SCE evaluates these agreements under authoritative accounting literature to determine whether such agreements contain a lease. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. Based on authoritative accounting guidance for leases, SCE then classifies each lease as capital or operating.

Table of Contents

As of December 31, 2009, SCE accounted for three power purchase agreements as capital leases. Gross capital leases reflected in "Utility plant" on the consolidated balance sheets were $248 million and $25 million at December 31, 2009 and 2008, respectively. The asset carrying amount, net of amortization, was $235 million and $16 million at December 31, 2009 and 2008, respectively. The related obligations were reflected on the consolidated balance sheets in "Other current liabilities" and "Other deferred credits and other long-term liabilities."

On December 7, 2001, a subsidiary of EME completed a sale-leaseback of EME's Homer City facilities to third-party lessors for an aggregate purchase price of $1.6 billion, consisting of $782 million in cash and assumption of debt (the fair value of which was $809 million). Under the terms of the 33.67-year leases, EME's subsidiary is obligated to make semi-annual lease payments on each April 1 and October 1. If a lessor intends to sell its interest in the Homer City facilities, EME has a right of first refusal to acquire the interest at fair market value. Minimum lease payments (included in the table above) are $155 million in 2010, $160 million in 2011, $160 million in 2012, $149 million in 2013, and $138 million in 2014, and the total remaining minimum lease payments are $1.4 billion. The gain on the sale of the facilities has been deferred and is being amortized over the term of the leases.

On August 24, 2000, a subsidiary of EME completed a sale-leaseback of EME's Powerton and Joliet power facilities located in Illinois to third-party lessors for an aggregate purchase price of $1.4 billion. Under the terms of the leases (33.75 years for Powerton and 30 years for Joliet), EME's subsidiary makes semi-annual lease payments on each January 2 and July 2, which began January 2, 2001. EME guarantees its subsidiary's payments under the leases. If a lessor intends to sell its interest in the Powerton or Joliet power facility, EME has a right of first refusal to acquire the interest at fair market value. Minimum lease payments (included in the table above) are $170 million in 2010, $151 million in each of 2011, 2012, 2013 and 2014. The total remaining minimum lease payments are $337 million. The gain on the sale of the power facilities has been deferred and is being amortized over the term of the leases.

Under the terms of the foregoing sale-leaseback transactions, distributions are restricted by EME's subsidiaries unless specified financial covenants are met. At December 31, 2009, EME's subsidiaries met these covenants. In addition, the lease agreements and the Midwest Generation credit agreement contain covenants that include, among other things, restrictions on the ability of these subsidiaries to incur debt, create liens on its property, merge or consolidate, sell assets, make investments, engage in transactions with affiliates, make distributions, make capital expenditures, enter into agreements restricting its ability to make distributions, engage in other lines of business, or engage in transactions for any speculative purpose.

The following summarizes the estimated remaining commitments (the majority of "other operating leases" are related to EME's long-term leases for the Illinois power facilities and

Table of Contents

Homer City facilities) for noncancelable operating leases and all contracts that meet the requirements for capital leases:

(in millions)	Operating Leases Power Contracts	Operating Leases Other	Capital Leases
2010	$ 728	$ 404	$ 37
2011	770	381	33
2012	691	373	33
2013	793	362	33
2014	699	330	33
Thereafter	8,116	1,877	489
Total future commitments	11,797	3,727	658
Amount representing executory costs			(144)
Amount representing interest			(279)
Net commitments	$ 11,797	$ 3,727	$ 235

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

Operating lease expense was $614 million in 2009, $583 million in 2008 and $539 million in 2007. The timing of SCE's recognition of the lease expense conforms to the ratemaking treatment for SCE's recovery of the cost of electricity. The amounts above do not include payments related to CDWR purchases for the benefit of SCE's customers, as SCE is acting as an agent for the CDWR.

Both capital and operating leases have varying terms, provisions and expiration dates. There were no sublease rentals and the contingent rentals for capital leases were less than $1 million for both 2009 and 2008.

Nuclear Decommissioning Commitment

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The liability to decommission SCE's nuclear power facilities is $3.1 billion as of December 31, 2009, based on site-specific studies performed in 2005 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 4.4% to 5.8%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable

Table of Contents

through rates in the future. If the assumed return on trust assets is greater than estimated, funding amounts may be reduced through future decommissioning proceedings.

Decommissioning of San Onofre Unit 1 is underway and will be completed in three phases: (1) decontamination and dismantling of all structures and some foundations; (2) spent fuel storage monitoring; and (3) fuel storage facility dismantling, removal of remaining foundations, and site restoration. Phase one was completed in 2008. Phase two activities commenced January 1, 2009 and will continue until spent fuel is transferred to the DOE currently planned to begin in 2035. Phase three activities are planned to be performed concurrently with San Onofre Units 2 and 3 decommissioning projects. In February 2004, SCE announced that it discontinued plans to ship the San Onofre Unit 1 reactor pressure vessel to a disposal site until such time as appropriate arrangements are made for its permanent disposal. It will continue to be stored at its current location within the north industrial area of San Onofre. Final disposition of the Unit 1 reactor pressure vessel has therefore been planned for phase three of the Unit 1 decommissioning project.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds and are subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($61 million at December 31, 2009). Total expenditures for the decommissioning of San Onofre Unit 1 were $595 million from the beginning of the project in 1998 through December 31, 2009.

Decommissioning expense under the rate-making method was $46 million each in 2009, 2008 and 2007. The ARO for decommissioning SCE's active nuclear facilities was $3.1 billion and $2.9 billion at December 31, 2009 and 2008, respectively.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

SCE has power purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table below). There are no requirements to make debt-service payments.

Certain commitments for the years 2010 through 2014 are estimated below:

(in millions)	**2010**	**2011**	**2012**	**2013**	**2014**
Fuel supply	$ 637	$ 405	$ 392	$ 172	$ 119
Gas and coal transportation payments	252	152	8	9	8
Purchased power	395	422	602	702	682

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the

Table of Contents

transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $45 million through 2016 (approximately $6 million per year).

At December 31, 2009, EME's subsidiaries had firm commitments to spend approximately $441 million in 2010 on capital and construction expenditures. The majority of these expenditures primarily relate to the construction of wind projects and non-environmental improvements at the fossil-fueled facilities. These expenditures are planned to be financed by cash on hand, cash generated from operations, and project level and turbine vendor financing. EME has secured $206 million in wind project financing.

EME has entered into various turbine supply agreements with vendors to support its wind development efforts. As of December 31, 2009, EME had commitments to purchase 183 wind turbines (349 MW) and had 67 wind turbines (163 MW) in storage to be used for future wind projects. EME has commitments on the turbines under purchase contracts and in storage of $463 million due in 2010 and $22 million due in 2011. As of December 31, 2009 and 2008, EME had $123 million and $318 million, respectively, in wind turbine deposits and $191 million and $9 million, respectively, related to wind turbines in storage included in other long-term assets on its consolidated balance sheet. EME continues to actively negotiate with its turbine suppliers to match turbine delivery and payment dates to the deployment of turbines at individual wind projects.

In February 2010, EME commenced construction of a 130 MW wind project in Oklahoma, which EME refers to as the Taloga wind project. EME plans to use 54 wind turbines currently in storage to complete the Taloga wind project. The project is scheduled for completion in late 2010. In February 2010, EME allocated turbines under one of its existing turbine supply agreements for 53 wind turbines (80 MW) to be used for the Laredo Ridge wind project located in Nebraska, which reduces the remaining turbines available for future projects to 302 MW. The Laredo Ridge wind project is being developed under a joint development agreement. EME intends to purchase the project in the second quarter of 2010. The project has contracted to sell power to the Nebraska Public Power District under a 20-year power sales contract and is expected to be completed in late 2010.

One of EME's existing turbine supply agreements can be terminated for convenience. Termination of this agreement in its entirety would further reduce turbine commitments by $84 million during 2010. In the event of such termination by EME, a write-off of approximately $21 million would be recognized.

At December 31, 2009, Midwest Generation and Homer City had fuel purchase commitments with various third-party suppliers for the purchase of coal. Based on the contract provisions, which consist of fixed prices, subject to adjustment clauses, these minimum commitments are estimated to aggregate $932 million, summarized as follows: $457 million in 2010, $263 million in 2011, and $212 million in 2012.

In January and February 2010, Midwest Generation and Homer City entered into additional contractual agreements for the purchase of coal. These commitments, together with estimated transportation costs under existing agreements through 2011, are estimated to be $22 million in 2010, $94 million in 2011, $33 million in 2012 and $33 million in 2013.

Table of Contents

In connection with the acquisition of the Midwest Generation plants, Midwest Generation 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 contract with a one-time payment 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, loss on termination of contract, asset write-down and other charges and credits, net" on EME's consolidated statements of income.

At December 31, 2009, EME had a contractual commitment to transport natural gas. EME's share of the commitment to pay minimum fees under its gas transportation agreement, which has a remaining contract length of eight years, is estimated to aggregate $41 million in the next five years, $8 million each year, 2010 through 2013, and $9 million in 2014. EME has entered into agreements to re-sell the transportation under this agreement which aggregates $50 million over the same period.

At December 31, 2009, Midwest Generation and Homer City had contractual agreements for the transport of coal to their respective facilities. The commitments under these contracts are based on either actual coal purchases or minimum quantities. Accordingly, contractual obligations for transportation based on actual coal purchases are derived from committed coal volumes set forth in fuel supply contracts. The minimum commitments under these contracts are estimated to aggregate $388 million, summarized as $244 million in 2010 and $144 million in 2011.

At December 31, 2009, EME and its subsidiaries were party to a long-term power purchase contract, a coal cleaning agreement, turbine operations and maintenance agreements, and agreements for the purchase of limestone, ammonia and materials used while operating environmental controls equipment. The minimum commitments under these contracts are estimated to aggregate $236 million for the next four years: $84 million in 2010, $69 million in 2011, $58 million in 2012, and $25 million in 2013.

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.

Environmental Indemnities Related to the Midwest Generation Plants

In connection with the acquisition of the Midwest Generation 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. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Also, in connection with the sale-leaseback transaction related to the Powerton and Joliet Stations in Illinois, EME agreed to indemnify the lessors for specified environmental liabilities. Due to the nature of the obligation under these indemnities, a maximum potential liability cannot be determined. Commonwealth Edison has 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 litigation discussed below under " Contingencies Midwest Generation New Source Review Lawsuit." The sale-leaseback participants have requested similar indemnification. Except as discussed below, EME has not recorded a liability related to these environmental indemnities.

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 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 2011. There were approximately 217 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2009. Midwest Generation had recorded a $50 million and $52 million liability at December 31, 2009 and 2008, respectively, related to this matter.

Midwest Generation recorded an undiscounted liability for its indemnity for future asbestos claims through 2045. During the fourth quarter of 2007, the liability was reduced by $9 million based on updated estimated losses. In calculating future losses, various assumptions were made, including but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that no asbestos claims will be filed after 2044.

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

Environmental Indemnity Related to the Homer City Facilities

In connection with the acquisition of the Homer City facilities, Homer City agreed to indemnify the sellers with respect to specified 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 Homer City. Also, in connection with the sale-leaseback transaction related to the Homer City facilities, Homer City agreed to indemnify the lessors for specified environmental liabilities. 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. For discussion of the NOV received by Homer City and associated indemnity claims, see "Contingencies Homer City New Source Review Notice of Violation." EME has not recorded a liability related to this indemnity.

Indemnities Provided under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2009 and 2008, EME had recorded a liability of $96 million (of which $56 million is classified as a current liability) and $95 million, respectively, related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2009, EME had recorded a liability of $2 million related to these matters.

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

SCE's Mountainview power 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 California Energy Commission permit. SCE 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 results of operations, financial position or liquidity.

Homer City New Source Review Notice of Violation

On June 12, 2008, Homer City received an NOV from the US EPA alleging that, beginning in 1988, Homer City (or former owners of the Homer City facilities) performed repair or

Table of Contents

replacement projects at Homer City Units 1 and 2 without first obtaining construction permits as required by the PSD requirements of the CAA. The US EPA also alleges that Homer City has failed to file timely and complete Title V permits. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. On June 30, 2009 and January 2, 2010, the US EPA issued requests for information to Homer City under Section 114 of the CAA. Homer City is working on a response to the requests. 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 cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations, financial position or cash flows.

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 Homer City acquired the Homer City facilities. The sellers responded by denying the indemnity obligation, but accepting a portion of defense costs related to the claims.

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 Homer City for costs and liabilities associated with the Homer City NOV. Homer City responded by undertaking the indemnity obligation and defense of the claims.

Environmental Developments

Midwest Generation Environmental Compliance Plans and Costs

Midwest Generation is subject to various requirements with respect to environmental compliance for the Midwest Generation plants. In 2006, Midwest Generation entered into an agreement with the Illinois EPA, which has been embodied in an Illinois rule called the CPS, to control emission of mercury, NO_x and SO_2 from its coal-fired plants. During 2008 and 2009, Midwest Generation installed equipment to reduce its mercury emissions. During 2009, Midwest Generation also conducted tests of NO_x removal technology based on SNCR and SO_2 removal using flue gas desulfurization technology based on dry sodium sorbent injection that may be employed to meet CPS requirements. Based on this testing, Midwest Generation has concluded that installation of SNCR technology on multiple units will meet the NO_x portion of the CPS. Capital expenditures for installation of SNCR technology are expected to be approximately $88 million in 2010 and $70 million in 2011.

Testing of flue gas desulfurization technology based on injection of dry sodium sorbent demonstrated significant reductions in SO_2 emissions when using low-sulfur coal employed by Midwest Generation; however, further analysis and evaluation are required to determine the appropriate method to comply with the SO_2 portion of the CPS. Use of flue gas desulfurization technology based on injection of dry sodium sorbent in combination with Midwest Generation's use of low-sulfur coal is expected to require substantially less capital and installation time than dry scrubber technology, but would likely result in higher ongoing operating costs and may consequently result in lower dispatch rates and competitiveness of the plants. Midwest Generation may also combine the use of dry sorbent injection technology with upgrades to its particulate removal systems to meet environmental regulations.

Table of Contents

Midwest Generation does not yet know what specific method of SO_2 removal will be used or the total costs that will be incurred to comply with the CPS. Any decision regarding whether or not to proceed with the above or other approaches to compliance remains subject to further analysis and evaluation of several factors, including market conditions, regulatory and legislative developments and forecasted capital and operating costs. Due to existing uncertainties about these factors, Midwest Generation may defer final decisions about particular units for the maximum time available. Accordingly, final decisions on whether to install controls, the particular controls that will be installed, and the resulting capital commitments may not occur for up to two years for some of the units and potentially further out for others. Midwest Generation could elect to shut down units when required in order to comply with the SO_2 removal requirements of the CPS. Midwest Generation continues to evaluate various scenarios and cannot predict the extent of shutdowns and retrofits or the particular combination of retrofits and shutdowns it may ultimately employ to comply with CPS.

Homer City Environmental Issues and Capital Resource Limitations

Homer City operates SCR equipment on all three units to reduce NO_x emissions, operates flue gas desulfurization equipment on Unit 3 to reduce SO_2 emissions, and uses coal-cleaning equipment onsite to reduce the ash and sulfur content of raw coal to meet both combustion and environmental requirements. Homer City may be required to install additional environmental equipment on Unit 1 and Unit 2 to comply with environmental regulations under the CAIR and Pennsylvania mercury regulations. If required, the timing of such compliance remains uncertain. Homer City projects that if flue gas desulfurization equipment becomes required, it would need to make capital commitments for such equipment three to four years in advance of the effectiveness of such requirements. Homer City continues to review technologies available to reduce SO_2 and mercury emissions and to monitor developments related to mercury and other environmental regulations. Restrictions under the agreements entered into as part of Homer City's 2001 sale-leaseback transaction could affect, and in some cases significantly limit or prohibit, Homer City's ability to incur indebtedness or make capital expenditures. Homer City will have limited ability to obtain additional outside capital for such projects without amending its lease and related agreements. EME is under no contractual or other obligation to provide funding to Homer City.

Greenhouse Gas Regulation Developments

The nature of future environmental regulation and legislation will have a substantial impact on Edison International. Edison International believes that resolution of current uncertainties about the future, through well-balanced and appropriately flexible regulation and legislation, is needed to support the necessary evolution of the electric industry into using cleaner, more efficient infrastructure and to attract the capital ultimately needed for this effort. Legislative, regulatory, and legal developments related to potential controls over greenhouse gas emissions in the United States are ongoing. Actions to limit or reduce greenhouse gas emissions could significantly increase the cost of generating electricity from fossil fuels as well as the cost of purchased power. In the case of utilities, like SCE, these costs are generally borne by customers, whereas the increased costs for competitive generators, like EME, must be recovered through market prices for electricity.

Table of Contents

Recent significant developments include the following:

- Legislation to regulate greenhouse gas emissions continues to be considered by Congress; however, the timing, content, and potential effects on Edison International and its subsidiaries of any greenhouse gas legislation that may be enacted remain uncertain.

- In December 2009, the US EPA issued a final finding that certain greenhouse gases, including carbon dioxide, threaten the public health and welfare. The US EPA has issued a proposed rule, known as the "greenhouse gas tailoring rule," under which all new and major modifications of existing stationary sources emitting 25,000 metric tons of carbon dioxide equivalents annually, including power plants, would be required to include BACT to minimize their greenhouse gas emissions. Since the current proposal affects only new or modified sources, it is not expected to have any immediate effect, if adopted, on existing fossil-fuel generating stations of SCE, Midwest Generation or Homer City, but it could affect the cost of new construction or modifications. US EPA could also use its authority in the future to regulate existing sources of greenhouse gas emissions. If controls are required to be installed at the facilities of Edison International subsidiaries in the future in order to reduce greenhouse gas emissions pursuant to regulations issued by the US EPA or others, the potential impact will depend on the nature of the controls applied, which remains uncertain.

- Three recent court cases addressed the question of whether power plants that emit greenhouse gases constituted public nuisances that could be held liable for damages or other remedies. In one case (in which Edison International is a named defendant): a California federal district court dismissed the plaintiffs' claims. In the other two, federal courts of appeals permitted the suits to go forward. Each of these differing results remains subject to appeal and thus the ultimate impact of these cases remains uncertain. Edison International cannot predict whether these recent decisions will result in the filing of new actions with similar claims or whether Congress, in considering climate legislation, will address directly the availability of courts for these sorts of claims.

- Governor Schwarzenegger issued an executive order to increase California's renewable energy goals from 20% to 33% and has directed the CARB to adopt a regulation consistent with 33% of retail sellers annual electricity sales being obtained from renewable energy sources by 2020. Achieving a 33% renewables portfolio standard in this timeframe is highly ambitious, given the magnitude of the infrastructure build-out required and the slow pace of transmission permitting and approvals. The CARB is also considering a number of direct regulations to reduce greenhouse gases in California, which requirements could go beyond those ultimately imposed by Congress or the US EPA.

Once-Through Cooling

Last year, the California State Water Resources Board released a draft policy, which would establish closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like San Onofre and many of the existing gas-fired power plants along the California coast. If the policy is adopted by the Board, it may result in significant capital expenditures at San Onofre and may affect its operations. It may also significantly impact SCE's ability to procure generating capacity from fossil-fuel plants that use ocean water in

Table of Contents

once-through cooling systems. It may also impact system reliability and the cost of electricity to the extent other coastal power plants in California are forced to shut down or limit operations. The policy has the potential to adversely affect California's nineteen once-through cooled power plants, which provide over 21,000 MW of combined, in-state generation capacity, including over 9,100 MW of capacity interconnected within SCE's service territory.

Environmental Remediation

Edison International is subject to numerous environmental laws and regulations, which typically require a lengthy and complex process for obtaining licenses, permits and approvals and 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.

Possible developments, such as the enactment of more stringent environmental laws and regulations, proceedings that may be initiated by environmental and other regulatory authorities, cases in which new theories of liability are recognized, and settlements agreed to by other companies that establish precedent or expectations for the power industry, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures or operational expenditures or the ceasing of operations at certain facilities. There is no assurance that additional costs would be recovered from customers or that Edison International's financial position results of operations and cash flows would not be materially affected.

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

As of December 31, 2009, Edison International's recorded estimated minimum liability to remediate its 28 identified sites at SCE (23 sites) and EME (5 sites primarily related to Midwest Generation) was $43 million, $39 million of which was related to SCE including $5 million related to San Onofre. 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 $178 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

Table of Contents

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 34 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $10 million.

The CPUC allows SCE to recover 90% of its environmental remediation costs at certain sites, representing $34 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 $36 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.

SCE 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 $30 million. Recorded costs were $11 million, $29 million and $25 million for 2009, 2008 and 2007, respectively.

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

Federal and State Income Taxes

Edison International's federal income tax returns are currently under active examination by the IRS for tax years 2003 through 2006 and are subject to examination through tax years 2008. Edison International's California and other state income tax returns remain open for tax years 1986 through 2008. As discussed in the section "Global Settlement" in Note 4, the Global Settlement was finalized on May 5, 2009 and effectively closed the federal income tax examination for tax years 1986 2002 and resolved federal tax disputes related to Edison Capital's cross-border, leveraged leases in their entirety.

FERC Transmission Incentives and CWIP Proceedings

In November 2007, the FERC issued an order granting ROE incentive adders, recovery of the ROE and incentive adders during the CWIP phase and recovery of abandoned plant costs (if any) for three of SCE's transmission projects; DPV2, Tehachapi and Rancho Vista. The

Table of Contents

FERC approved, subject to refund, SCE's annual filing requests to collect its CWIP return of $37 million for 2008, $39 million for 2009, and $46 million for 2010. The 2008 and 2009 CWIP returns are currently being recovered in rates, subject to refund, and the 2010 CWIP return is expected to be recovered in rates beginning on June 1, 2010.

Midwest Generation New Source Review Lawsuit

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 PSD requirements and of the New Source Performance Standards of the CAA, including alleged requirements to obtain a construction permit and to install controls sufficient to meet BACT emissions rates at the time of the projects. The US EPA also alleged that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the CAA. Finally, the US EPA alleged violations of certain opacity and particulate matter standards at the Midwest Generation plants. At approximately the same time, Commonwealth Edison received an NOV substantially similar to the Midwest Generation NOV. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ, along with several Chicago-based environmental action groups, had discussions designed to explore the possibility of a settlement but no settlement resulted.

On August 27, 2009, the US EPA and the State of Illinois filed a complaint in the Northern District of Illinois against Midwest Generation, but not Commonwealth Edison, alleging claims substantially similar to those in the NOV. In addition to seeking penalties ranging from $25,000 to $37,500 per violation, per day, the complaint calls for an injunction ordering Midwest Generation to install controls sufficient to meet BACT emissions rates at all units subject to the complaint; to obtain new PSD or NSR permits for those units; to amend its applications under Title V of the CAA; to conduct audits of its operations to determine whether any additional modifications have occurred; and to offset and mitigate the harm to public health and the environment caused by the alleged CAA violations. The remedies sought by the plaintiffs in the lawsuit could go well beyond those required under the CPS. By order dated January 19, 2010, the court allowed a group of Chicago-based environmental action groups to intervene in the case.

The owner participants of the Powerton and Joliet Stations have sought indemnification and defense from Midwest Generation and/or EME for costs and liabilities associated with these matters. EME responded by undertaking the indemnity obligation and defense of the claims.

An adverse decision could involve penalties and remedial actions that would have a material adverse impact on the financial condition and results of operations of EME. EME cannot predict the outcome of these matters or estimate the impact on its facilities, its results of operations, financial position or cash flows.

Table of Contents

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 against SCE, among other defendants, arising out of the coal supply agreement for Mohave. Subsequently, the Hopi Tribe was added as an additional plaintiff. 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 Navajo's complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion. In April 2009, in a related case filed in December 1993 against the U.S. Government, the U.S. Supreme Court found that the Navajo Nation did not have a claim for compensation. SCE cannot predict the outcome of the Tribes' complaints against SCE.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.6 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($375 million). The balance is covered by a loss sharing program among nuclear reactor licensees. 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, all nuclear reactor licensees could be required to contribute their share of the liability in the form of a deferred premium.

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. 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 federal 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.

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 contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. Currently, both San Onofre and Palo Verde have interim storage for spent nuclear fuel on site sufficient for the current license period.

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 trial was completed in April 2009 but no decision has been issued. SCE cannot predict the outcome of this proceeding or when a decision will be issued by the Court.

Note 7. Accumulated Other Comprehensive Income

Edison International's accumulated other comprehensive income consists of:

(in millions)	Unrealized Gain (Loss) on Cash Flow Hedges	Foreign Currency Translation Adjustment	Pension and PBOP Net Gain (Loss)	Pension and PBOP Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2007	$ (60)	$ (1)	$ (34)	$ 3	$ (92)
Change for 2008	300	(3)	(36)	(2)	259
Balance at December 31, 2008	240	(4)	(70)	1	167
Change for 2009	(135)	4		1	(130)
Balance at December 31, 2009	$ 105	$	$ (70)	$ 2	$ 37

Unrealized gain/(loss) on cash flow hedges, net of tax, at December 31, 2009 primarily consisted of commodity hedge gains of $106 million.

Unrealized gains on commodity hedges consist primarily of Midwest Generation and 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, $99 million, after tax, of the net unrealized gains on cash flow hedges at December 31, 2009 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.

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. Lehman Brothers Commodity Services also filed for bankruptcy protection on October 3, 2008. The obligations of Lehman Brothers Commodity Services under the power contracts were guaranteed by Lehman Brothers Holdings. These contracts qualified as cash flow hedges until EME de-designated the power contracts effective September 12, 2008 when it determined that it was no longer probable that performance would occur. The amount recorded in accumulated other comprehensive income (loss) related to the effective portion of the hedges was $24 million pre-tax ($15 million, after tax) on that date. Since the power contracts are no longer being accounted for as cash flow hedges and subsequently were terminated, the subsequent change in fair value was recorded as an unrealized loss in 2008 and included in operating revenues on EME's consolidated statement of income. In 2009, $14 million of the pre-tax amount recorded in accumulated other comprehensive income (loss) was reclassified to operating revenues. The remaining amount will be reclassified in 2010, unless it becomes probable that the forecasted transactions will no longer occur.

EME has established claims in the amount of $48 million related to the contracts terminated with Lehman Brothers Holdings and its subsidiary as described above through the termination provisions of its master netting agreements with a Lehman Brothers Holdings subsidiary. Such claims have been fully reserved and are included net in prepaid expenses and other on EME's consolidated balance sheets.

Note 8. Property and Plant

Competitive Power Generation and Other Property

Competitive power generation and other property included on the consolidated balance sheets is comprised of the plant and related facilities of EME, Edison Capital and VIEs consolidated by SCE:

	December 31,	
(in millions)	**2009**	**2008**
Building, plant and equipment	$ 5,192	$ 5,250
Emission allowances	1,305	1,305
Leasehold improvements	156	132
Furniture and equipment	75	82
Land (including easements)	31	80
Construction in progress[1]	619	544
	7,378	7,393
Accumulated provision for depreciation	(2,231)	(2,019)
Competitive power generation and other property net	$ 5,147	$ 5,374

1 Construction in progress consisted of $451 million and $276 million at December 31, 2009 and 2008, respectively, related to wind projects including those under construction.

The power sales agreements of certain EME wind projects qualify as operating leases pursuant to authoritative accounting for leases. The carrying amount and related accumulated depreciation of the property of these wind projects totaled $1.3 billion and $123 million, respectively, at December 31, 2009. EME records rental income from wind projects that are accounted for as operating leases as electricity is delivered at rates defined in power sales agreements. Revenue from these power sales agreements were $83 million, $46 million and $24 million in 2009, 2008 and 2007, respectively.

In connection with Midwest Generation's financing activities, EME has given a first priority security interest in substantially all of the coal-fired generating plants owned by Midwest Generation and the assets relating to those plants, and receivables of EMMT directly related to Midwest Generation's hedging activities. The total amount of assets pledged or mortgaged was approximately $2.8 billion at December 31, 2009. In addition to these assets, Midwest

Table of Contents

Generation's membership interests and the capital stock of Edison Mission Midwest Holdings were pledged. Emission allowances have not been pledged.

On March 12, 2009, the CPUC issued a final decision in SCE's 2009 GRC, authorizing the transfer of the Mountainview power plant to utility rate base. SCE received FERC and other necessary approvals, and on July 1, 2009, terminated the FERC-approved power-purchase agreement between Mountainview Power Company, LLC and SCE, and transferred assets and liabilities valued at $680 million and $173 million, respectively. The transfer resulted in a $603 million increase in SCE's utility plant (primarily generation plant) with a corresponding decrease in competitive power generation and other property (primarily building, plant and equipment). In addition, SCE recognized a one time, non-cash accounting benefit of approximately $46 million primarily resulting from the establishment of regulatory assets to recognize differences in the accounting treatment for non-regulated and rate-regulated entities mainly related to AFUDC-equity. There was no economic impact to customers from this change as compared to the FERC-approved power-purchase agreement, as these amounts would have been recognized over the life of that agreement and have no impact on cash flows.

Asset Retirement Obligations

In 2003, Edison International recorded the fair value of its liability for legal AROs, which are primarily related to the decommissioning of SCE's nuclear power facilities. SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs and the recovery of the costs through the rate-making process. SCE has collected in rates amounts for the future cost of removal of its nuclear assets and has placed those amounts in independent trusts. For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6 and "Nuclear Decommissioning Trusts" in Note 10.

A reconciliation of the changes in the ARO liability is as follows:

(in millions)	**2009**	**2008**	**2007**
Beginning balance	$ 3,042	$ 2,892	$ 2,759
Accretion expense	188	176	169
Revisions	6	(13)	3
Liabilities added	6	22	7
Liabilities settled	(1)	(35)	(46)
Ending balance	$ 3,241	$ 3,042	$ 2,892

The ARO liability as of December 31, 2009 includes an ARO liability of $3.1 billion related to nuclear decommissioning.

Table of Contents

Note 9. Supplemental Cash Flows Information

The following is Edison International's supplemental cash flows information:

(in millions)		Years ended December 31, 2009		2008		2007
Cash payments (receipts) for interest and taxes:						
Interest net of amounts capitalized	$	661	$	608	$	709
Tax payments (refunds) net		427		377		332
Noncash investing and financing activities:						
Details of capital lease obligations:						
Capital lease purchased	$	(223)	$		$	(10)
Capital lease obligation issued		223				10
Dividends declared but not paid:						
Common Stock	$	103	$	101	$	99
Preferred and preference stock of utility not subject to mandatory redemption	$	13	$	13	$	13
Details of assets acquired:						
Fair value of assets acquired	$	14	$		$	41
Liabilities assumed		3				
Net assets acquired	$	11	$		$	41
Details of consolidation of variable interest entities:						
Assets	$	3	$	3	$	12
Liabilities		(4)		(4)		(5)

In connection with certain wind projects acquired during the past three years, the purchase price included payments that were due upon the start and/or completion of construction. Accordingly, EME accrued for estimated payments or made payments that were due upon commencement of construction and/or completion of construction scheduled during 2007 through 2009.

Note 10. Fair Value Measurements

Fair value is defined 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"). Fair value for a liability should reflect the entity's non-performance risk. Fair value is determined using a hierarchy to prioritize the inputs to valuation models. 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 are:

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

Table of Contents

Level 2 Pricing inputs that 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 derivative 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 peak and AEP/Dayton) adjusted for nonperformance 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 the fair value of these positions. Broker quotes or prices from exchanges are used to validate and corroborate the primary source. These price quotations reflect mid-market prices (average of bid and ask) and are obtained from sources that EME believes to provide the most liquid market for the commodity. EME considers broker quotes to be observable when corroborated with other information which may include a combination of prices from exchanges, other brokers and comparison to executed trades.

SCE's Level 2 derivatives primarily consist of financial natural gas swaps, fixed float 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 and Intercontinental Exchange. Level 2 also includes Edison Capital's foreign currency swap contract which is valued primarily using published foreign currency rates.

Level 3 includes the majority of SCE's derivatives, including over-the-counter options, bilateral contracts, capacity contracts, and QF contracts. The fair value of these SCE derivatives is determined using uncorroborated non-binding broker quotes (from one or more brokers) and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Broker quotes are obtained from several brokers and compared against each other for reasonableness. SCE has Level 3 fixed float swaps for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange. However, these swaps have contract terms that extend beyond observable market data and the unobservable inputs incorporated in the fair value determination are considered significant compared to the overall swap's fair value.

Table of Contents

Level 3 also includes derivatives that trade infrequently (such as firm transmission rights and CRRs in the California market, financial transmission rights traded in markets outside California and over-the-counter derivatives at illiquid locations) and long-term power agreements. For illiquid financial transmission rights and CRRs, Edison International reviews objective criteria related to system congestion 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 and natural gas 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.

Derivatives with counterparties that have significant nonperformance risks are classified as Level 3. In assessing nonperformance risks, Edison International 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 nonperformance. The fair value of derivative assets and derivative liabilities nonperformance risk was $4 million and $7 million, respectively, at December 31, 2009 and was $6 million and zero, respectively, at December 31, 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.

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.

Table of Contents

The following table sets forth assets and liabilities that were accounted for at fair value as of December 31, 2009 by level within the fair value hierarchy.

(in millions)	Level 1	Level 2	Level 3	Netting and collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$ 1,526	$	$	$	$ 1,526
Derivative contracts	17	245	516	(153)	625
Long-term disability plan	8				8
Nuclear decommissioning trusts[3]					
Stocks[4]	1,772				1,772
Municipal bonds		634			634
Corporate bonds[5]		393			393
U.S. government and agency securities	240	68			308
Short-term investments, primarily cash equivalents	1	14			15
Sub-total of nuclear decommissioning trusts	$ 2,013	$ 1,109	$	$	$ 3,122
Total assets[6]	$ 3,564	$ 1,354	$ 516	$ (153)	$ 5,281
Liabilities at Fair Value					
Derivative contracts	(3)	(256)	(454)	77	(636)
Net assets (liabilities)	$ 3,561	$ 1,098	$ 62	$ (76)	$ 4,645

The following table sets forth assets and liabilities that were accounted for at fair value as of December 31, 2008 by level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$ 3,583	$	$ 3	$	$ 3,586
Derivative contracts	4	419	448	(300)	571
Long-term disability plan	7				7
Nuclear decommissioning trusts[3]					
Stocks[4]	1,308				1,308
Municipal bonds		629			629
U.S. government and agency securities	172	132			304
Corporate bonds[5]		260			260
Short-term investments, primarily cash equivalents	4	23			27
Sub-total of nuclear decommissioning trusts	$ 1,484	$ 1,044	$	$	$ 2,528
Total assets[6]	$ 5,078	$ 1,463	$ 451	$ (300)	$ 6,692
Liabilities at Fair Value					
Derivative contracts	(2)	(397)	(753)	198	(954)
Net assets (liabilities)	$ 5,076	$ 1,066	$ (302)	$ (102)	$ 5,738

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, restricted cash, short-term investments and prepaid expenses and other on Edison International's consolidated balance sheet.

3

Excludes net assets/(liabilities) of $18 million and $(4) million at December 31, 2009 and 2008, respectively, of interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

4

At December 31, 2009 and 2008, respectively, approximately 67% and 68% of the equity investments were located in the United States.

5

Corporate bonds are diversified. At December 31, 2009 and 2008, respectively, this category included $50 million and $72 million for collateralized mortgage obligations and other asset backed securities.

6

Excludes $32 million at both December 31, 2009 and December 31, 2008, of cash surrender value of life insurance investments for deferred compensation.

Table of Contents

The following table sets forth a summary of changes in the fair value of Level 3 assets and liabilities:

(in millions)	December 31, 2009	December 31, 2008
Fair value, net at beginning of period	$ (302)	$ 98
Total realized/unrealized gains (losses):		
Included in earnings[1]	7	297
Included in regulatory assets and liabilities[2]	312	(645)
Included in accumulated other comprehensive income	3	(2)
Purchases and settlements, net	27	(52)
Transfers in or out of Level 3	15	2
Fair value, net at end of period	$ 62	$ (302)
Change during the period in unrealized gains (losses) related to assets and liabilities held at the end of the period[3]	$ 449	$ (448)

1 Reported in "Competitive power generation" revenue on Edison International's consolidated statement of income.

2 Due to regulatory mechanisms, SCE's realized and unrealized gains and losses are recorded as regulatory assets and liabilities.

3 Amounts reported in "Competitive power generation" revenue on Edison International's consolidated statements of income were $64 million and $125 million for the years ended December 31, 2009 and 2008, respectively. The remainder of the unrealized gains relate to SCE. See (2) above.

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.

The following table sets forth amortized cost and fair value of the trust investments:

(in millions)			Amortized Cost December 31, 2009	Amortized Cost December 31, 2008	Fair Value December 31, 2009	Fair Value December 31, 2008
Stocks			$ 822	$ 839	$ 1,772	$ 1,308
Municipal bonds	2010	2047	545	561	634	629
Corporate bonds	2010	2044	309	214	393	260
U.S. government and agency securities	2010	2039	287	268	308	304
Short-term investments and receivables/payables	2010		33	24	33	23
Total			$ 1,996	$ 1,906	$ 3,140	$ 2,524

Note: Maturity dates as of December 31, 2009.

Table of Contents

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Realized gains were $242 million, $201 million and $85 million in 2009, 2008 and 2007, respectively. Realized losses were $147 million, $155 million and less than a million for 2009, 2008 and 2007, respectively. Proceeds from sales of securities (which are reinvested) were $2.2 billion, $3.1 billion and $3.7 billion for 2009, 2008 and 2007, respectively. Unrealized holding gains, net of losses, were $1.1 billion and $618 million at December 31, 2009 and 2008, respectively. Approximately 92% of the cumulative trust fund contributions were tax-deductible.

The following table sets forth a summary of changes in the fair value of the trust for the year ended December 31, 2009:

(in millions)		2009
Balance at beginning of period	$	2,524
Realized gains net		95
Unrealized gains net		526
Other-than-temporary impairments		(111)
Interest, dividends, contributions and other		106
Balance at end of period	$	3,140

Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on operating revenue or earnings.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. These contributions are determined based on an analysis of the liquidation value of the trusts, 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 during the intervening 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. On April 3, 2009, SCE submitted its triennial nuclear decommissioning application, requesting that its trust fund contributions increase to approximately $64.5 million per year, beginning on January 1, 2011. 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.

Long-term Debt

The carrying amounts and fair values of long-term debt are:

	December 31,							
	2009				2008			
(in millions)		Carrying Amount		Fair Value		Carrying Amount		Fair Value
Long-term debt, including current portion	$	10,814	$	10,452	$	11,124	$	10,812

Table of Contents

Fair values of long-term debt are based on third-party evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes of new issue prices and relevant credit information.

Note 11. Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded electric utility revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Under-collections are recorded as regulatory balancing account assets. Over-collections are recorded as regulatory balancing account liabilities. SCE's regulatory balancing accounts accumulate balances until they are refunded to or received from SCE's customers through authorized rate adjustments. Primarily all of SCE's balancing accounts can be classified as one of the following types: generation-revenue related, distribution-revenue related, generation-cost related, distribution-cost related, transmission-cost related or public purpose and other cost related.

Balancing account under-collections and over-collections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts.

Table of Contents

Regulatory assets included on the consolidated balance sheets are:

	December 31,	
(in millions)	**2009**	**2008**
Current:		
Regulatory balancing accounts	$ 94	$ 455
Energy derivatives	25	138
Other	1	12
	$ 120	$ 605
Long-term:		
Regulatory balancing accounts	$ 43	$ 29
Deferred income taxes net	1,561	1,337
ARO		224
Unamortized nuclear investment net	340	375
Nuclear-related ARO investment net	258	278
Unamortized coal plant investment net	73	79
Unamortized loss on reacquired debt	287	309
Pensions and other postretirement benefits	1,014	1,882
Energy derivatives	357	723
Environmental remediation	36	40
Other	170	138
	$ 4,139	$ 5,414
Total Regulatory Assets	$ 4,259	$ 6,019

SCE's regulatory asset related to energy derivatives is primarily an offset to unrealized losses on recorded derivatives. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to income taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory asset related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's nuclear-related regulatory assets related to San Onofre are expected to be recovered by 2022. SCE's nuclear-related regulatory assets related to Palo Verde are expected to be recovered by 2027. SCE's net regulatory asset related to its unamortized coal plant investment is being recovered through June 2016. Although SCE's unamortized nuclear and coal plant investments are classified as regulatory assets on the consolidated balance sheets, they continue to be a component of rate base and earned an 8.75% return in both 2009 and 2008. SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 29 years. SCE's regulatory asset related to pensions and other post-retirement plans represents the recoverable portion of the additional amounts recorded in accordance with authoritative guidance on accounting for pensions and post-retirement plans (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be recovered through rates charged to customers. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

Table of Contents

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

	December 31,			
(in millions)		**2009**		**2008**
Current:				
Regulatory balancing accounts	$	363	$	1,068
Other		4		43
	$	367	$	1,111
Long-term:				
Regulatory balancing accounts	$	642	$	43
ARO		171		
Costs of removal		2,515		2,368
Employee benefit plans				70
	$	3,328	$	2,481
Total Regulatory Liabilities	$	3,695	$	3,592

SCE's regulatory liability related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent operating revenue collected for asset removal costs that SCE expects to incur in the future. SCE's regulatory liabilities related to employee benefit plan expenses represent pension costs recovered through rates charged to customers in excess of the amounts recognized as expense or the difference between these costs calculated in accordance with rate-making methods and these costs calculated in accordance with authoritative guidance on employers accounting for pensions, and PBOP costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will be returned to ratepayers in some future rate-making proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process, or be applied as otherwise directed by the CPUC.

Table of Contents

Note 12. Other Income and Expenses

Other income and expenses are as follows:

(in millions)	Years ended December 31, 2009	2008	2007
Equity AFUDC	$ 116	$ 54	$ 46
Increase in cash surrender value of life insurance policies	23	24	23
Energy settlement	9	3	4
Other	12	20	16
Total utility other income	$ 160	$ 101	$ 89
Competitive power generation other income	11	12	6
Total other income	$ 171	$ 113	$ 95
Various penalties	$	$ 59	$ 5
Civic, political and related activities and donations	28	34	25
Other	21	30	15
Total utility other expenses	$ 49	$ 123	$ 45
Competitive power generation other expenses	8	2	
Total other expenses	$ 57	$ 125	$ 45

Note 13. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's proportionate share of expenses for each project is included on the consolidated statements of income.

The following is SCE's investment in each project as of December 31, 2009:

(in millions)	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 73	$ 13	60%
Pacific Intertie	182	62	50
Generating stations:			
Four Corners Units 4 and 5(coal)	580	477	48
Mohave (coal)	351	303	56
Palo Verde (nuclear)	1,858	1,527	16
San Onofre (nuclear)	5,131	4,075	78
Total	$ 8,175	$ 6,457	

All of Mohave and a portion of San Onofre and Palo Verde are included in regulatory assets on the consolidated balance sheets see Note 11. Mohave ceased operations on December 31,

Table of Contents

2005. In December 2006, SCE acquired the City of Anaheim's approximately 3% ownership interest of San Onofre Units 2 and 3.

Note 14. Variable Interest Entities

As of December 31, 2009, the FASB authoritative guidance defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. This guidance identifies the primary beneficiary as the variable interest holder that absorbs a majority of expected losses; if no variable interest holder meets this criterion, then it is the variable interest holder that receives a majority of the expected residual returns. The primary beneficiary is required to consolidate the variable interest entity unless specific exceptions or exclusions are met. Edison International uses variable interest entities to conduct its business as described below.

Description of Use of Variable Interest Entities

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

EME's subsidiaries and affiliates have financed the development and construction or acquisition of its projects by capital contributions from EME and the incurrence of debt or lease obligations by its subsidiaries and affiliates owning the operating facilities. These project level debt or lease obligations are generally structured as non-recourse to EME, with several exceptions, including EME's guarantee of the Powerton and Joliet leases as part of a refinancing of indebtedness incurred by its project subsidiary to purchase the Midwest Generation plants. As a result, these project level debt or lease obligations have structural priority with respect to revenues, cash flows and assets of the project companies over debt obligations incurred by EME as a holding company. Distributions to EME from projects are generally only available after all current debt service or lease obligations at the project level have been paid and are further restricted by contractual restrictions on distributions included in the documentation evidencing the project level debt obligations. 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.

In seeking to find and invest in new wind projects, EME has entered into joint development agreements with third-party development companies that provide for funding by an EME subsidiary of development costs including through loans (referred to as development loans) and joint decision-making on key contractual agreements such as power purchase contracts, site agreements and permits. Joint development agreements and development loans may be for a specific project or a group of identified and future projects and generally grant EME the exclusive right to acquire related projects. In addition to joint development agreements, EME may purchase wind projects from third-party developers in various stages of development, construction or operation.

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

Edison Capital, through its subsidiaries, has invested in real estate projects. These projects consist primarily of multi-family residential properties located throughout the United States that provide affordable housing for low and moderate income households. These real estate investments qualify for various tax credits, including state and federal low-income housing tax credits, and the federal historic tax credit. With a few exceptions, the projects are managed and operated by unrelated parties and project debt is non-recourse to Edison Capital. The general partner in these entities is generally the primary beneficiary based on absorbing the majority of expected losses.

Categories of Variable Interest Entities

Projects or Entities that are Consolidated

EME has purchased a majority interest in a number of wind projects under joint development agreements with third-party developers. At December 31, 2009 and 2008, EME had majority interests in 15 wind projects with a total generating capacity of 700 MW and 630 MW, respectively, that have minority interests held by others. The projects are located in Iowa, Minnesota, New Mexico, Nebraska and Texas. Minority interest holders have key rights over matters such as incurrence of debt and sale of the project, and in certain cases, receive a higher allocation of income and losses after a minimum return is earned by EME. In determining that EME was the primary beneficiary, a key factor was the conclusion that the power sales agreements did not constitute a variable interest since the agreements are operating leases and do not absorb expected losses. Based on the allocation of income and losses, EME expects to earn a majority of the expected gains or absorb the majority of the expected losses from these entities and, therefore, determined that it is the primary beneficiary.

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by a related party, EME. The QFs sell electricity to SCE and steam to nonrelated parties. SCE has determined that it is the primary beneficiary of these four variable interest entities and therefore consolidates these projects.

In determining that SCE was the primary beneficiary, SCE considered the term of the contract, percentage of plant capacity, pricing, and other variable interests. SCE performed a quantitative assessment which included the analysis of the expected losses and expected residual returns of the entity by using the various estimated projected cash flow scenarios associated with the assets and activities of that entity. The quantitative analysis provided

Table of Contents

sufficient evidence to determine that SCE was the primary beneficiary absorbing a majority of the entity's expected losses, receiving a majority of the entity's expected residual returns, or both.

Project	Capacity	Termination Date[1]	EME Ownership
Kern River	300 MW	June 2011	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

1 As mandated by the CPUC, Midway-Sunset, Sycamore Cogeneration and Watson sell electricity to SCE under an extension of their prior power purchase agreements, with revised pricing. On September 28, 2009, Midway-Sunset entered into a power purchase agreement with PG&E, that expires in 2016, for which CPUC approval is pending. Sycamore Cogeneration entered into a new steam supply agreement with Chevron North America Exploration and Production Company that expires in 2013.

The following table presents summarized financial information of the SCE QFs and EME wind projects that were consolidated at December 31, 2009 and 2008:

(in millions)	December 31, 2009	December 31, 2008
Current assets	$ 247	$ 206
Competitive power generation and other property	1,197	1,239
Other long-term assets	6	3
Total assets	$ 1,450	$ 1,448
Current liabilities	$ 80	$ 92
Asset retirement obligation	17	15
Long-term obligations net of current maturities	20	25
Deferred revenues	58	15
Other long-term liabilities	21	18
Total liabilities	$ 196	$ 165
Noncontrolling interests[1]	$ 250	$ 268

1 The noncontrolling interests related to SCE's VIEs take into consideration EME's ownership in the Big 4 projects.

Assets serving as collateral for the debt obligations related to the wind projects had a carrying value of $81 million and $85 million at December 31, 2009 and 2008, respectively, and primarily consist of property, plant and equipment. The consolidated statements of income and cash flow for the years ended December 31, 2009 and 2008 includes $12 million and $4 million of pre-tax loss, respectively, and $37 million and $30 million of operating cash flow, respectively, related to variable interest entities that are consolidated.

SCE's VIE projects do not have any third party debt outstanding. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any profit or loss generated by these entities will not affect SCE's income statement. Any liabilities of these projects are nonrecourse to SCE.

Projects that are not Consolidated

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

EME owns a number of domestic energy projects through partnerships in which it has a 50% or less ownership interest. Entities formed to own these projects are generally structured with a management committee in which EME exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. Two of these projects have long-term debt that is secured by a pledge of the assets of the project entity, but do not provide for any recourse to EME. Accordingly, a default on a long-term financing of a project could result in foreclosure on the assets of the project entity resulting in a loss of some or all of EME's project investment, but would not require EME to contribute additional capital. At December 31, 2009, entities which EME has accounted for under the equity method had indebtedness of $245 million, of which $104 million is proportionate to EME's ownership interest in these projects. At December 31, 2008, entities which EME has accounted for under the equity method had indebtedness of $294 million, of which $128 million is proportionate to EME's ownership interest in these projects.

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

Edison Capital's maximum exposure to loss from affordable housing investments in this category is generally limited to its net investment balance of $3 million and recapture of tax credits (estimated at $31 million as of December 31, 2009).

Entities with Unavailable Financial Information

SCE also has seven other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under this standard and continues to attempt to obtain information for these projects in order to determine whether the projects should be consolidated. These entities are not legally obligated to provide financial information to SCE and have declined to do so. Because these potential VIEs were created prior to December 31, 2003, SCE is not required to apply this accounting guidance to these entities as long as SCE continues to be unable to obtain this information. The aggregate capacity dedicated to SCE for these projects was 263 MW at both December 31, 2009 and 2008. The amount that SCE paid to these projects was $129 million, $203 million and $180 million for 2009, 2008 and 2007, respectively. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

Table of Contents

Note 15. Preferred and Preference Stock of Utility Not Subject to Mandatory Redemption

SCE's authorized shares are: $100 cumulative preferred 12 million shares, $25 cumulative preferred 24 million shares and preference with no par value 50 million shares. There are no dividends in arrears for the preferred stock or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the years ended December 31, 2009 and 2008. In January 2008, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. There is no sinking fund requirement for redemptions or repurchases of preferred stock.

Shares of SCE's preference stock rank junior to all of the preferred stock and senior to all common stock. Shares of SCE's preference stock are not convertible into shares of any other class or series of SCE's capital stock or any other security. The preference shares are noncumulative and have a $100 liquidation value. There is no sinking fund for the redemption or repurchase of the preference shares.

SCE's preferred and preference stock not subject to mandatory redemption is:

(in millions, except per-share amounts)	Shares Outstanding	Redemption Price	December 31, 2009	2008
Cumulative preferred stock				
$25 par value:				
4.08% Series	650,000	$ 25.50	$ 16	$ 16
4.24% Series	1,200,000	$ 25.80	30	30
4.32% Series	1,653,429	$ 28.75	41	41
4.78% Series	1,296,769	$ 25.80	33	33
Preference stock				
No par value:				
5.349% Series A	4,000,000	$ 100.00	400	400
6.125% Series B	2,000,000	$ 100.00	200	200
6.00% Series C	2,000,000	$ 100.00	200	200
			920	920
Less issuance costs			(13)	(13)
Total			$ 907	$ 907

The Series A preference stock, issued in 2005, may not be redeemed prior to April 30, 2010. After April 30, 2010, SCE may, at its option, redeem the shares in whole or in part and the dividend rate may be adjusted. The Series B preference stock, issued in 2005, may not be redeemed prior to September 30, 2010. After September 30, 2010, SCE may, at its option, redeem the shares in whole or in part. The Series C preference stock, issued in 2006, may not be redeemed prior to January 31, 2011. After January 31, 2011, SCE may, at its option, redeem the shares in whole or in part. No preference stock not subject to mandatory redemption was redeemed in the last three years.

Table of Contents

At December 31, 2009 accrued dividends related to SCE's preferred and preference stock not subject to mandatory redemption were $13 million.

Note 16. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a competitive power generation segment (EME), and a financial services and other segment (Edison Capital and other EMG subsidiaries). Edison International evaluates performance based on net income attributable to common shareholders.

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.

The significant accounting policies of the segments are the same as those described in Note 1.

In the past three fiscal years, EME's merchant plants sold electric power generally into the PJM market by participating in PJM's capacity and energy markets or by selling capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 48%, 50% and 51% of EME's consolidated operating revenues for the years ended December 31, 2009, 2008 and 2007, respectively. For the years ended December 31, 2009 and 2008, a second customer, Constellation Energy Commodities Group, Inc. accounted for 16% and 10%, respectively, 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. In 2008 and 2007, EME also derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Illinois Plants to Commonwealth Edison under load requirements services contracts. These contracts had all expired by May 2009. Sales under these contracts accounted for 12% and 19% of EME's consolidated operating revenues for the years ended December 31, 2008 and 2007, respectively.

Table of Contents

Reportable Segments Information

The following is information (including the elimination of intercompany transactions) related to Edison International's reportable segments:

(in millions)	Electric Utility	Competitive Power Generation	Financial Services and Other[1]	Parent and Other[2]	Edison International
			Year ended December 31, 2009		
Operating revenue	$ 9,965	$ 2,377	$ 22	$ (3)	$ 12,361
Depreciation, decommissioning and amortization	1,178	236	3	1	1,418
Interest and dividend income	11	19	11	(9)	32
Equity in income (loss) from partnerships and unconsolidated subsidiaries net		100	(11)	(47)	42
Interest expense net of amounts capitalized	420	296	10	6	732
Income tax expense (benefit) continuing operations	249	10	(294)	(63)	(98)
Income (loss) from continuing operations	1,371	207	(598)	(28)	952
Net income (loss) attributable to common shareholders	1,226	203	(598)	18	849
Total assets	32,474	8,521	1,022	(573)	41,444
Capital expenditures	2,999	283			3,282
			Year ended December 31, 2008		
Operating revenue	$ 11,248	$ 2,811	$ 54	$ (1)	$ 14,112
Depreciation, decommissioning and amortization	1,114	194	4	1	1,313
Interest and dividend income	22	36	12	(8)	62
Equity in income (loss) from partnerships and unconsolidated subsidiaries net		122	(3)	(88)	31
Interest expense net of amounts capitalized	407	279	9	5	700
Income tax expense (benefit) continuing operations	342	243	29	(18)	596
Income (loss) from continuing operations	904	500	60	(116)	1,348
Net income (loss) attributable to common shareholders	683	501	60	(29)	1,215
Total assets	32,568	9,016	3,089	(58)	44,615
Capital expenditures	2,267	552	5		2,824

Table of Contents

(in millions)	Year ended December 31, 2007				
Operating revenue	$ 10,233	$ 2,580	$ 56	$ (1)	$ 12,868
Depreciation, decommissioning and amortization	1,011	162	9	(1)	1,181
Interest and dividend income	44	98	16	(4)	154
Equity in income from partnerships and unconsolidated subsidiaries net		200	28	(149)	79
Interest expense net of amounts capitalized	429	313	10		752
Income tax expense (benefit) continuing operations	337	173	(2)	(16)	492
Income (loss) from continuing operations	1,063	341	70	(167)	1,307
Net income (loss) attributable to common shareholders	707	340	70	(19)	1,098
Total assets	27,477	7,263	3,008	(225)	37,523
Capital expenditures	2,286	540			2,826

1 Includes amounts from EMG subsidiaries that are not significant as a reportable segment.

2 Includes amounts from Edison International (parent), other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

The net income (loss) attributable to common shareholders reported for competitive power generation includes earnings from discontinued operations of $(7) million for 2009, less than one million for 2008 and $(2) million for 2007.

Geographic Information

Edison International's foreign and domestic revenue and assets information is:

	Years ended December 31,		
(in millions)	2009	2008	2007
Revenue			
United States			