EDISON INTERNATIONAL
Form 10-K
February 28, 2011

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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, 2010

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 $10.3 billion on or about June 30, 2010, based upon prices reported on the New York Stock Exchange. As of February 24, 2011, 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 2011 Annual Meeting of Shareholders	Part III

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GLOSSARY

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

2010 Tax Relief Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
AFUDC	allowance for funds used during construction
Ambit project	American Bituminous Power Partners, L.P.
AOI	Adjusted Operating Income (Loss)
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
coal plants	Midwest Generation coal plants and Homer City plant
CPS	Combined Pollutant Standard
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DOE	U.S. Department of Energy
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
FIP(s)	federal implementation plan(s)
Four Corners	coal fueled electric generating facility located in Farmington, New Mexico in which SCE holds a 48% ownership interest
GAAP	generally accepted accounting principles
GHG	greenhouse gas
Global Settlement	A settlement between Edison International and the IRS that 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 for tax years 1986 through 2002 and related matters with state tax authorities.
GRC	General Rate Case
GWh	Gigawatt-hours
HAPs	Hazardous Air Pollutants
Homer City	EME Homer City Generation L.P.
Illinois EPA	Illinois Environmental Protection Agency
IRS	Internal Revenue Service
ISO	Independent System Operator

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kWh(s)	kilowatt-hour(s)
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations in this report
Midwest Generation	Midwest Generation, LLC
Midwest Generation plants	EME's power plants (fossil fuel) located in Illinois
MMBtu	million British thermal units
Mohave	two coal fueled electric generating facilities that no longer operate located in Clark County, Nevada in which SCE holds a 56% ownership interest
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	large pressurized water nuclear electric generating facility located near Phoenix, Arizona in which SCE holds a 15.8% ownership interest
PBOP(s)	Postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
QF(s)	qualifying facility(ies)
ROE	return on equity
RPM	reliability pricing model
RTO(s)	Regional Transmission Organization(s)
S&P	Standard & Poor's Ratings Services
San Onofre	large pressurized water nuclear electric generating facility located in south San Clemente, California in which SCE holds a 78.21% ownership interest
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
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
US EPA	U.S. Environmental Protection Agency
VIE(s)	variable interest entity(ies)

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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:

- cost of capital and the ability of Edison International or its subsidiaries to borrow funds and access the capital markets on reasonable terms;
- 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;
- 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;
- 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 of equipment; and availability and cost of spare parts;
- 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;
- changes in interest rates and 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;
- 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;
- 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;

- 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;
- 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;
- risks that competing transmission systems will be built by merchant transmission providers in SCE's territory: and
- weather conditions and natural disasters.

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.

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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"), a competitive power generation company, and Edison Capital, an infrastructure finance company. EME and Edison Capital are 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, 2010, Edison International and its subsidiaries had an aggregate of 20,117 full-time employees. 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 two business segments for financial reporting purposes: an electric utility operation segment (SCE) and a competitive power generation segment (EMG). SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to an approximately 50,000-square-mile area of southern California. The SCE service territory contains a population of over 13 million people. In 2010, SCE's total operating revenue was derived as follows: 43.5% commercial customers, 39.5% residential customers, 6.0% industrial customers, 1.3% resale sales, 5.8% public authorities, and 3.9% agricultural and other customers. SCE had 18,230 full-time employees at December 31, 2010. SCE's operating revenue was approximately $10 billion in 2010.

Sources of power to serve SCE's customers during 2010 were approximately: 42% purchased power; 24% CDWR; and 34% SCE-owned generation.

SCE 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. SCE also files a joint Proxy Statement with its parent, Edison International. Such reports and Proxy Statement are 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 subsidiary, EME. EME is also 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. Some of the facilities are operated on a merchant basis, with energy being sold into the marketplace, and others are operated under contracts calling for the delivery of energy to specific purchasers. EME also engages in hedging and energy trading activities in competitive power markets through its Edison Mission Marketing & Trading, Inc. ("EMMT") subsidiary. At December 31, 2010, EME and its subsidiaries employed 1,833 people.

EME's subsidiaries or affiliates have typically been formed to own full or partial interests in one or more power generation facilities 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, which include

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wind projects and one biomass project. As of December 31, 2010, EME's subsidiaries and affiliates owned or leased interests in 39 operating projects with an aggregate net physical capacity of 10,979 MW of which EME's pro rata share was 9,852 MW. At December 31, 2010, EME's subsidiaries and affiliates also owned four wind projects under construction totaling 480 MW of net generating capacity. EME's consolidated operating revenue in 2010 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. Such reports are 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.

Prior to January 1, 2010, Edison International reported three business segments: electric utility operations (SCE), competitive power generation (EME) and financial services and other (Edison Capital and other EMG subsidiaries). As a result of termination of Edison Capital's cross-border leases during 2009 and the continued reduction of its remaining portfolio, the remaining business activity is no longer significant enough to report separately. Accordingly, the financial services and other segment has been combined into the competitive power generation segment for all periods presented. The combination of these business activities is consistent with the management structure of EMG and evaluation of performance by Edison International.

Edison International maintains a property and casualty insurance program for itself and its subsidiaries, which includes business interruption (for EMG only), and excess liability insurance covering liabilities to third parties for bodily injury or property damage resulting from operations. These policies are subject to specific retentions, sublimits and deductibles, which are comparable to those carried by other utility and electric generating companies of similar size. SCE also has separate insurance programs for nuclear property and liability, workers compensation and solar rooftop construction. EMG maintains a separate wind liability insurance program for its wind projects. For further information on wildfire insurance issues, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 10. Regulatory and Environmental Developments."

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 Public Utility Holding Company Act 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.

SCE's rates and operations are subject to extensive regulation by the CPUC, FERC, NRC, CEC, and CAISO. EMG's operating projects are also subject to energy, environmental and other governmental laws and regulations at the federal, state and local levels, and EMG is additionally subject to the market rules, procedures, and protocols of the markets in which it participates. Both SCE and EMG 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. The 1988 CPUC decision authorizing SCE to reorganize into a holding company structure, however, contains certain obligations on Edison International and its affiliates. These include providing the CPUC access to certain records, establishing accounting procedures to protect against subsidization of nonutility activities by SCE's customers, and following transfer pricing rules. In addition, the decision provides 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, among other requirements, prohibit holding companies from (1) being used as a conduit to provide non-public information to a utility's affiliate and (2) causing or abetting a utility's violation of the rules, including providing preferential treatment to affiliates.

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 funding and costs, and aspects of the transmission system, planning, site identification and construction. The governing body of the CPUC consists of five Commissioners who are appointed by the Governor of California, confirmed by the California Senate and serve for six-year staggered terms.

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.

NERC

The NERC establishes and enforces reliability standards and critical infrastructure protection standards for the bulk power system. The critical infrastructure protection standards focus on controlling access to critical physical and cyber security assets. Compliance with these standards is mandatory. The maximum penalty that may be levied for violating a NERC reliability or critical infrastructure protection standard is $1 million per violation, per day.

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 CAISO, 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 are also necessary for the project to proceed.

CEC

The construction, planning, and project site identification of SCE's power plants of 50 MW or greater within California are subject to the jurisdiction of the CEC. The CEC is also responsible for forecasting future energy needs. These forecasts are used by the CPUC in determining the adequacy of SCE's electricity procurement plans.

Nuclear Power Plant Regulation

SCE is subject to the jurisdiction of the 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.

The NRC has continued to affirm that San Onofre is being operated safely. However, SCE has had to address a number of regulatory and performance issues for which corrective action is required to mitigate exposure to events that could have safety significance. In its September 1, 2010 mid-cycle performance review letter the NRC noted that although San Onofre had developed corrective actions to resolve previously noted human performance and problem identification and resolution issues, the corrective actions that had been implemented had not been fully effective. The NRC is conducting inspections over its baseline program, including inspections to evaluate progress on these issues, and to assess actions taken to improve the working environment for employees to feel free to raise safety concerns. The NRC is also conducting additional public meetings to discuss these issues. To address these regulatory and performance issues, SCE has applied increased management focus and other resources to San Onofre, with an associated impact on operations and maintenance costs. SCE anticipates that its corrective actions, and related additional management focus and operations and maintenance costs, will continue. If issues identified by the NRC remain uncorrected, these issues could have a material adverse effect on SCE.

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, 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 operations and maintenance expense. The return is established by multiplying an authorized rate of return, determined in separate cost of capital proceedings (as discussed below), by SCE's investment in the generation and distribution rate base. In the GRC proceedings, the CPUC also generally approves the level of 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 GRC decision for the 2009-2011 period was issued in March 2009 and was effective as of January 1, 2009. In the 2009 GRC, the CPUC determined the 2010 and 2011 authorized revenues by escalating the entire revenue requirement. 2009's authorized revenue requirement of $4.83 billion was escalated by 4.25% to create the 2010 authorized amount, which was in turn escalated by 4.35% to create the 2011 authorized amount. SCE filed its 2012 GRC application with the CPUC on November 23, 2010, to be effective on January 1, 2012. The CPUC has authorized a revenue decoupling mechanism, which allows the difference between the revenue authorized and the actual volume of electricity sales to be collected from or refunded to ratepayers. Accordingly, SCE is neither benefited nor burdened by the volumetric risk related to retail 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. In 2009, the CPUC granted SCE's request to extend 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 established for 2013 and beyond. 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 and cost of capital proceedings. 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 recoverable or refundable and will therefore impact earnings.

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Cost-Recovery Rates

Cost-recovery mechanisms allow SCE to recover its costs, but do not allow a return. These mechanisms are used to recover SCE's costs of fuel, purchased-power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation 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 authorizes the use of a balancing account to eliminate the effect on earnings from differences in revenue resulting from actual and forecasted electricity sales. 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. For 2011, the trigger amount is approximately $252 million.

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 Mechanism ("Energy Efficiency Mechanism") which allows SCE to earn incentives based on SCE's performance toward meeting CPUC energy efficiency goals. In December 2010, the CPUC modified and extended the existing Energy Efficiency Mechanism to apply to the 2009 energy efficiency program. Under the modified mechanism, SCE has the opportunity to earn an incentive of 7% of the value of the total energy efficiency savings created, if SCE achieves 85% or more of the CPUC's energy efficiency goals for the 2009 energy efficiency program year.

In November 2010, the CPUC issued a draft decision in a new rulemaking intended to review the framework of the Energy Efficiency Mechanism and to establish a mechanism applicable to performance during the 2010 2012 energy efficiency program cycle. SCE cannot predict when a final decision will be issued, the content of such final decision or the amount of earnings, if any, that SCE may receive as a result of the adoption of a new mechanism.

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, PG&E and SDG&E). SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges 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; but do affect customer rates. The remaining CDWR power contracts that were allocated to SCE terminate by the end of 2011. The bond-related charges and direct access exit fees continue until 2022.

Competition

Because SCE is an electric utility company operating within a defined service territory pursuant to authority from the CPUC, SCE faces retail 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 statute 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 sales by qualifying facilities, 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.

Natural Gas Supply

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

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	2017
Conversion	2018
Enrichment	2020
Fabrication	2016

Coal Supply

On January 1, 2010, SCE and the other Four Corners participants entered into a Four Corners Coal Supply Agreement with the BHP Navajo Coal Company, under which coal will be supplied to Four Corners Units 4 and 5 until July 6, 2016. In November 2010, SCE entered into an agreement to sell its interest in Four Corners subject to certain conditions and regulatory approvals.

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. The CAISO schedules 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. SCE participates in the day-ahead and real-time markets for the sale of its generation and purchases of its load requirements.

The CAISO uses a nodal locational pricing model, which sets wholesale electricity prices at system points ("nodes") that reflect local generation and delivery costs. Generally, SCE schedules its 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 lines ranging from 33 kV to 500 kV and substations. SCE's distribution system, which takes power from substations to customers, includes over 60,000 circuit miles of overhead lines, 43,500 circuit miles of underground lines and over 700 distribution substations, all of which are located in California.

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

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
Peaker Plants (4)	Various	Gas fueled Combustion Turbine	100%	196	196
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]	1,500	720
Total				9,820	5,502

1 In November 2010, SCE entered into an agreement to sell its interest in Four Corners to APS for approximately $294 million. The sale is contingent upon the satisfaction of several conditions and the obtaining of multiple regulatory approvals. Currently SCE estimates that the sale will close in the second half of 2012. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment" for more information.

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.

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Twenty-eight 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 2011 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 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. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Debt and Credit Agreements."

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 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. For more information on SCE's sale of its interest in Four Corners, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment."

Seasonality

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

EDISON MISSION GROUP INC.

Regulation

Federal Power Act

The FERC has 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). 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. Previously approved rates may also be revoked or modified by the FERC after notice and opportunity for hearing.

The FERC also has 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. Dispositions of EMG's jurisdictional assets and certain types of financing arrangements may require FERC approval.

Each of EMG's domestic generating facilities is either a qualifying facility, as determined by the FERC, or the subsidiary owning the facility is an EWG. Most qualifying facilities, including EMG's qualifying facilities, are exempt from the ratemaking and several other provisions of the Federal Power Act. EMG's EWGs are subject to the FERC's ratemaking jurisdiction under the Federal Power Act, but have been authorized by the FERC to sell power at market-based rates. In addition, EMG'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 Federal Power Act.

If one of the projects in which EMG has an interest were to lose its qualifying facility or EWG status, the project would no longer be entitled to the related exemptions from regulation and could become subject to rate regulation by the FERC and state authorities. Loss of status could also trigger defaults under covenants contained in the project's power sales agreements and financing agreements.

Transmission of Wholesale Power

Generally, projects that sell power to wholesale purchasers other than the local utility to which the project may be 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.

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. 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 addition, capacity markets in various regional wholesale power markets compensate supply resources for the capability to supply electricity when needed, and demand resources, for electricity they avoid using.

Wholesale Markets

EMG's largest power plants are its coal power plants located in Illinois, which are collectively referred to as the Midwest Generation plants in this annual report, and the Homer City plant located in Pennsylvania. Collectively, both the Midwest Generation plants and the Homer City plant are referred to as the coal plants in this annual report. The coal plants 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. Sales may also be made from PJM into the MISO RTO, which includes all or parts of Illinois, Wisconsin, Indiana, Michigan, Ohio

and other states in the region, and into the NYISO, which controls the transmission grid and energy and capacity markets for New York State.

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 requires all load-serving entities and generators, such as Midwest Generation and Homer City, to maintain prescribed levels of capacity, including a reserve margin, to ensure system reliability. PJM's capacity markets have a single market-clearing price for each capacity zone. In May of every year, PJM conducts an annual capacity auction ("RPM") to commit generation, energy efficiency and demand side resources three years forward, and to provide a long-term pricing signal for capacity resources.

Fuel Supply

The Midwest Generation plants purchase coal from several suppliers that operate mines in the Southern PRB of Wyoming. The total volume of coal consumed annually is largely dependent on the amount of generation and ranges between 17.5 million to 19.5 million tons. Coal is transported under long-term transportation agreements with Union Pacific Railroad and various short-haul carriers. Midwest Generation's long-term rail transportation contract with Union Pacific Railroad expires at the end of 2011. See "Item 1A. Risk Factors Risks Related to EMG Market Risks." As of December 31, 2010, Midwest Generation leased approximately 3,900 railcars to transport the coal from the mines to the generating stations and the leases have remaining terms that range from less than one year to nine years, with options to extend the leases or purchase some railcars at the end of the lease terms.

Homer City's Units 1 and 2 collectively consumes approximately 3.3 million to 3.5 million tons of mid-range sulfur coal per year. Two types of coal are purchased, ready-to-burn and raw coal. Ready-to-burn coal is of the quality that can be burned directly in Units 1 and 2, whereas the raw coal purchased for consumption by Units 1 and 2 must be cleaned in the Homer City coal cleaning facility, which has the capacity to clean up to 5 million tons of coal per year. Unit 3 consumes approximately 2 million tons of coal per year and can consume either raw or ready-to-burn coal. A wet scrubber FGD system for Unit 3 enables this unit to burn less expensive, higher sulfur coal, while still meeting environmental standards for emission control. In general, the coal purchased for all three units is acquired locally and originates from mines that are within approximately 100 miles of the Homer City plant. Homer City purchases the majority of its coal under term contracts with the balance purchased in the spot market as needed.

Competition

EMG is subject to competition from energy marketers, public utilities, government-owned power agencies, industrial companies, financial institutions, and other independent power producers. These companies may have competitive advantages as a result of scale, the location of their generation facilities, or other factors. Some of EMG'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.

State and local environmental regulations, particularly those that impose stringent state-specific emission limits in Illinois, could put EMG's coal plants at a disadvantage compared with competing power plants operating in nearby states and subject to less stringent state emission limits or to federal emission limits alone, and the CPS could put the Midwest Generation plants at a disadvantage compared with competing plants not subject to similar regulations. Potential future climate change regulations could also put EMG's coal 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 base mechanisms. In addition, the ability of these plants to compete may be affected by governmental and regulatory activities designed to support the construction and operation of power generation facilities fueled by renewable energy sources.

Asset Management and Trading Activities

EMG's power marketing and trading subsidiary, EMMT, manages the energy and capacity of EMG's merchant generating plants and, in addition, trades electric power, gas, oil and related commodity and

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financial products, including forwards, futures, options and swaps. EMMT segregates its activities into two categories:

Asset Management 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 EMG's subsidiaries that own or lease EMG's facilities. EMG uses derivative instruments to reduce its exposure to market risks that arise from price fluctuations of electricity, capacity, fuel, emission allowances, and transmission rights. The objective of these activities is to sell the output of EMG's facilities on a forward basis or to hedge the risk of future changes in prices. Hedging activities include on-peak and off-peak periods and may include load service requirements contracts with local utilities. Transactions related to hedging activities are designated separately from EMMT's trading activities. Not all contracts entered into by EMMT for hedging purposes qualify as hedges for accounting purposes.

Trading As an extension of its asset management 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 EMG's risk management committee.

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Properties

Power Plants in Operation

As of December 31, 2010, EMG'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%	5,172	5,172
Midwest Generation plants[1]	Illinois	PJM	oil	100%	305	305
Homer City plant[1]	Pennsylvania	PJM	coal	100%	1,884	1,884
Merchant Wind						
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 (4)[1]	California	PG&E	natural gas	50%	152	76
Sunrise[1]	California	CDWR	natural gas	50%	572	286
Renewable Energy						
Buffalo Bear	Oklahoma	WFEC	wind	100%	19	19
Cedro Hill	Texas	CSA	wind	100%	150	150
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[4]	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%	108	108
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	Republic of Turkey	TEDAS	natural gas	80%	180	144
Total					10,979	9,852

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.

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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
CSA	City of San Antonio		
ERCOT	Electric Reliability Council of Texas	PSCO	Public Service Company of Oklahoma
IPLC	Interstate Power and Light Company		
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 Comprised of seven individual wind projects.

Renewable Development Activities

At December 31, 2010, EMG had a development pipeline of potential wind projects with projected installed capacity of approximately 3,600 MW and had four projects totaling 480 MW under construction. Projects under construction at December 31, 2010 were as follows:

Wind Project	Location	Primary Electric Purchaser	Ownership Interest	EME's Capacity Pro Rata Share (in MW)
Big Sky	Illinois	Merchant[1]	100%	240
Taloga	Oklahoma	Oklahoma Gas and Electric Company[2]	100%	130
Laredo Ridge	Nebraska	Nebraska Public Power District[2]	100%	80
CWN	Minnesota	Northern States Power Company[2]	99%	30
Total				480

1 Plan to sell renewable energy credits into the PJM market as merchant generator or to third-party customers under power sales contracts. Sold 48 MW of capacity into a forward-year RPM auction.

2 Twenty-year power purchase agreement.

Laredo Ridge and Big Sky achieved commercial operation on February 1, 2011 and February 18, 2011, respectively. EMG anticipates that the remaining projects under construction will also achieve commercial operation in 2011. In addition to the projects under construction at

December 31, 2010, EMG expects the 55 MW Pinnacle project in West Virginia will commence construction in 2011 with anticipated commercial operation in 2011. For more information, see "Edison International Overview EMG Renewable Program" in the MD&A.

Significant Customers

For information on EMG's significant customers, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Derivative Instruments and Hedging Activities."

Energy and Infrastructure Investments

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

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As of December 31, 2010, Edison Capital is the lessor with an investment balance (including current lease receivable) of $166 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	$ 73
Beaver Valley: selling power to Ohio Edison Company, Centerior Energy Corporation	836 MW nuclear power plant	Shippingport, Pennsylvania	2017	$ 53
American Airlines	3 Boeing 767 ER aircraft	Domestic and international routes	2016	$ 40

Seasonality

Due to fluctuations in electric demand resulting from warm weather during the summer months and cold weather during the winter months, electric revenues from the coal plants normally 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, income from the coal plants is seasonal and has 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 Coal Plants" in the MD&A.

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.

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 EMG'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.

Edison International continues to monitor legislative and regulatory developments and to evaluate possible strategies for compliance with environmental regulations. Additional information about environmental matters affecting Edison International, including projected environmental capital expenditures, is included in the MD&A under the heading "SCE: Liquidity Capital Investment Plan" and in "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies" and "Note 10. Regulatory and Environmental Developments."

Greenhouse Gas Regulation

There have been a number of federal and state legislative and regulatory initiatives to reduce GHG emissions. Any climate change regulation or other legal obligation that would require substantial reductions in emissions of GHGs or that would impose additional costs or charges for the emission of GHGs could significantly increase the cost of generating electricity from fossil fuels, and especially from coal-fired plants, as well as the cost of purchased power, which could adversely affect Edison International.

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Federal Legislative/Regulatory Developments

Efforts to pass comprehensive federal climate change legislation have not yet been successful. The timing, content and potential effects on Edison International of any legislation that may be enacted remain uncertain. However, the US EPA has begun to issue federal GHG regulations that are likely to impact the operations of Edison International's subsidiaries.

In June 2010, the US EPA issued the Prevention of Significant Deterioration ("PSD") and Title V Greenhouse Gas Tailoring Rule, known as the "GHG tailoring rule." This regulation generally subjects newly constructed sources of GHG emissions and newly modified existing major sources to the PSD air permitting program beginning in January 2011 (and later, to the Title V permitting program under the CAA); however the GHG tailoring rule significantly increases the emissions thresholds that apply before facilities are subjected to these programs. The emissions thresholds for CO_2 equivalents in the final rule vary from 75,000 tons per year to 100,000 tons per year depending on the date and whether the sources are new or modified.

A challenge to the GHG tailoring rule (along with other GHG regulations and determinations issued by the US EPA) is pending before the U.S. Court of Appeals for the D.C. Circuit. Regulation of GHG emissions pursuant to the PSD program could affect efforts to modify EMG's or SCE's facilities in the future, and could subject new capital projects to additional permitting and pollution control requirements that could delay such projects. If EMG or SCE is required to install controls in the future or otherwise modify its operations in order to reduce GHG emissions, the potential impact of the GHG tailoring rule will depend on the nature and timing of the controls or modifications, which remain uncertain.

In December 2010, the US EPA announced that it had entered into a settlement with various states and environmental groups to resolve a long-standing dispute over regulation of GHGs from electrical generating units pursuant to the New Source Performance Standards in the CAA. Under the pending settlement, the US EPA will propose performance standards for GHG emissions from new and modified power plants and emissions guidelines for existing power plants in July 2011, and will finalize such regulations by May 2012, with compliance dates for existing power plants expected to be in 2015 or 2016. The specific requirements will not be known until the regulations are finalized.

Since January 2010, the US EPA's Final Mandatory GHG Reporting Rule has required all sources within specified categories, including electric generation facilities, to monitor emissions and to submit annual reports to the US EPA by March 31 of each year, with the first report due on March 31, 2011. EMG's 2010 GHG emissions were approximately 50.2 million metric tons. SCE's 2010 GHG emissions were approximately 6.5 million metric tons.

Regional Initiatives and State Legislation

Regional initiatives and state legislation may also require reductions of GHG emissions and it is not yet clear whether or to what extent any federal legislation would preempt them. If state and/or regional initiatives remain in effect after federal legislation is enacted, generators and utilities could be required to satisfy them in addition to the federal standards.

Edison International subsidiary operations in California are subject to two laws governing GHG emissions. The first law, the California Global Warming Solutions Act of 2006 (also referred to as AB 32), establishes a comprehensive program to reduce GHG emissions. AB 32 requires the California Air Resources Board ("CARB") to develop regulations, effective in 2012, that would reduce California's GHG emissions to 1990 levels in yearly increments by 2020. In December 2010, the CARB finalized regulations establishing a California cap-and-trade program, which include revisions to the CARB's mandatory GHG emissions reporting regulation. The regulations and the cap-and-trade program itself are being challenged by various citizens' groups under the California Environmental Quality Act.

The second law, SB 1368, required the CPUC and the CEC to adopt GHG emission performance standards restricting the ability of California investor-owned and publicly owned utilities, respectively, to enter into long-term arrangements for the purchase of electricity. The standards that have been adopted prohibit these entities, including SCE, from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, the performance of a combined-cycle gas turbine generator. Accordingly, the prohibition applies to most coal-fired plants. Utility purchases of power

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generated by EMG's California facilities are subject to the emissions performance standards established in SB 1368. EMG believes that all of its California facilities meet SB 1368 standards, but EMG 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. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment" for information on the sale of SCE's interest in Four Corners.

California law also requires SCE to increase its 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 provided from such resources (the "RPS Program") by no later than December 31, 2010 or such later date as flexible compliance requirements permit. Through December 31, 2010, SCE estimates its delivery of eligible renewable resources to customers to be 19% of its total energy portfolio. In accordance with the procurement rules and regulations, SCE expects to demonstrate full compliance with the RPS Program in its March 2011 filing. In addition, in September 2010, the CARB adopted a Renewable Electricity Standard, which requires SCE to demonstrate renewable energy production equal to 33% of its sales to retail customers for 2020 and each year thereafter. Subsequently, in February 2011, a California Senate bill was introduced that would impose a similar requirement that California utilities purchase 33% of their electricity requirements from renewable resources. It is unclear whether the legislation will preempt the CARB's standard, if it is enacted.

Edison International subsidiary operations in California and New Mexico may also be affected by the Western Climate Initiative ("WCI"), an agreement entered into by California, other western states and certain Canadian provinces, to develop strategies to reduce GHG emissions in the region to 15% below 2005 levels by 2020. In July 2010, the WCI partners released a comprehensive strategy for a regional cap-and-trade program, with a planned start date of January 2012, to help achieve their reduction goal. Recent political developments make it uncertain whether this regional program will proceed and what form it might take. As noted above, California is implementing its own program to reduce GHG emissions.

EMG's operations in Illinois may be affected by the Midwestern Greenhouse Gas Reduction Accord, an initiative by which six Midwestern states, including Illinois, and the Canadian province of Manitoba agreed to develop regional GHG emission reduction goals using a multi-sector cap-and-trade program. In May 2010, the Midwestern Greenhouse Gas Reduction Accord Advisory Group finalized recommendations and a model rule for emissions reduction targets and the design of a regional cap-and-trade program to serve as a basis for individual state legislative or regulatory action. However, there is substantial uncertainty as to whether the parties to the Midwestern Greenhouse Gas Reduction Accord intend to continue their efforts to develop or implement such a program, especially in light of the failure to pass a federal cap-and-trade program in the 111th Congress.

Litigation Developments

Litigation alleging that GHG is a public and private nuisance may affect Edison International and its subsidiaries, whether or not they are named as defendants. The law is unsettled on whether this litigation presents questions capable of judicial resolution or political questions that should be resolved by the legislative or executive branches.

In December 2010, the U.S. Supreme Court agreed to review a case in which an appellate panel had endorsed the availability of judicial remedies for nuisance allegedly caused by GHG emissions associated with climate change. Oral argument before the Supreme Court is scheduled for April 2011. Currently pending, while the Supreme Court considers the matter before it, is an appeal before the Ninth Circuit of a federal district order dismissing a case against Edison International and other defendants brought by the Alaskan Native Village of Kivalina in which the plaintiffs seek damages of up to $400 million for the cost of relocating the village, which plaintiffs claim is no longer protected from storms because the Arctic sea ice has melted as the result of climate change. Edison International and the other defendants in the lawsuit recently requested the Ninth Circuit to defer oral argument on the appeal pending the Supreme Court's decision on related issues.

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Edison International cannot predict whether the legal principles emerging from the Supreme Court or any of the cases in the appellate courts 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 to resolve claims associated with climate change.

Air Quality

The CAA, which regulates air pollutants from mobile and stationary sources, has a significant impact on the operation of fossil fuel plants, especially coal-fired plants. The CAA requires the US EPA to establish concentration levels in the ambient air for six criteria pollutants 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 SO_2.

Federal environmental regulations of these criteria pollutants require states to adopt state implementation plans, known as SIPs, for certain pollutants, which detail how the state will attain the standards that are mandated by the relevant law or regulation. The SIPs must be equal to or more stringent than the federal requirements and must be submitted to the US EPA for approval. 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. If the attainment status of areas changes, states may be required to develop new SIPs that address the changes. Many of EMG's facilities are located in areas that have not attained NAAQS for ozone (affected by NO_x emissions from power plants) and fine particulate matter (affected by SO_2 and NO_x emissions from power plants) and much of Southern California is in a non-attainment area for several criteria pollutants.

As described further below, on December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA, which was subsequently embodied in an Illinois rule called the Combined Pollutant Standard or "CPS," to reduce mercury, NO_x and SO_2 emissions at the Midwest Generation plants. The CPS 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 the CPS.

Nitrogen Oxide and Sulfur Dioxide

Clean Air Interstate and Transport Rules

The CAIR, issued by the US EPA on March 10, 2005, mandated significant reductions in NO_x and SO_2 emission allowance caps under the CAA in 28 eastern states and the District of Columbia. In 2008, the U.S. Court of Appeals for the D.C. Circuit initially vacated the CAIR, but later remanded the CAIR to the US EPA for the issuance of a revised rule. The CAIR will remain in effect until the US EPA finalizes a revised regulation.

In July 2010, the US EPA issued a Notice of Proposed Rulemaking for a proposed rule, known as the Transport Rule, which would require 31 eastern states (including Pennsylvania and Illinois) and the District of Columbia to reduce power plant emissions of NO_x and SO_2 substantially, starting in 2012, with additional reductions in 2014. The Transport Rule would replace the CAIR.

The US EPA has proposed allocating emission allowances based on the historic and projected emissions data from power plants, along with three possible approaches to emissions allowance trading. Under its preferred approach, a pollution limit would be set for each state, intrastate trading of allowances would be permitted among power plants, and limited interstate trading would also be permitted consistent with the requirement that each state meet its own pollution control obligations. Under the first alternative, a pollution limit would be set for each state, and only intrastate trading of allowances would be permitted. Under the second alternative, a pollution limit would be set for each state, an emissions limit would be set for each power plant, and limited emissions averaging would be permitted among affected units. In January 2011, the US EPA proposed two other possible approaches to emission allowance allocation. Both approaches would allocate allowances among units within each state based on each unit's proportional

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share of the state's total historic heat input, and the second approach would add a constraint based on a unit's reasonably foreseeable maximum emissions under the proposed Transport Rule trading programs.

The Transport Rule is scheduled to be finalized in 2011. The CAIR will remain in place until that time. Depending on the approach adopted, the Transport Rule may provide allowance allocations for the Midwest Generation plants which are adequate for the plants' needs or may require the Midwest Generation plants to procure additional allowances, based on projected emissions using the Illinois CPS allowable emission rates. The Transport Rule may require the installation of additional environmental equipment on Units 1 and 2 at the Homer City plant to reduce SO_2 emissions and, depending on the approach adopted, may also require Homer City to procure a significant number of additional allowances pending such installation or curtail operations if it is unable to do so on acceptable terms.

Proposed NAAQS for Sulfur Dioxide

In June 2010, the US EPA finalized the primary NAAQS for SO_2 by establishing a new one-hour standard at a level of 75 parts per billion. The final standard is being taken into account in EMG's environmental compliance strategy. Revisions to SIPs to achieve compliance with the new standard are due to be submitted to the US EPA by February 2014, with a compliance deadline of August 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 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.

The CPS also specifies the control technologies that 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 required Midwest Generation to shut down Unit 6 at the Waukegan Station by December 31, 2007, and Units 1 and 2 at the Will County Station by December 31, 2010, which it has done.

During 2009, Midwest Generation also conducted tests of NO_x 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 NO_x portion of the CPS. Capital expenditures for installation of SNCR equipment are expected to be approximately $109 million in 2011.

Testing of dry scrubbing using Trona on select Midwest Generation units has demonstrated significant reductions in SO_2 emissions. Use of this technology in conjunction with low sulfur coal is expected to require substantially less capital and time than spray dryer absorber technology, but would likely result in higher ongoing operating costs and may consequently result in lower dispatch rates and competitiveness of Midwest Generation's plants, depending on competitors' costs. For further discussion, see "Edison International Overview Environmental Developments Midwest Generation and Compliance Plans and Cost" in the MD&A.

Pennsylvania

The Homer City plant was subject to CAIR during 2010 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

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Pennsylvania CAIR, which is substantially similar to the federal CAIR, in the same manner in which it complies with the federal CAIR.

Mercury/Hazardous Air Pollutants

Clean Air Mercury Rule/Hazardous Air Pollutant 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. In February 2007, the U.S. Court of Appeals for the D.C. Circuit vacated both the CAMR and the related US EPA decision to remove oil- and coal-fired power plants from the list of sources to be regulated under the provisions of the CAA governing the emissions of HAPs.

In accordance with a consent decree entered in April 2010, the US EPA committed to proposing regulations by March 2011 limiting emissions of HAPs from coal- and oil-fired electrical generating units that are major sources of HAPs, and to finalizing such regulations by November 2011. The emissions standards must be designed to achieve the maximum degree of emission reduction that the US EPA determines is achievable for the affected units, taking into account costs and non-air quality environmental and health benefits (also referred to as maximum achievable control technology, or MACT, standard). Unlike the CAMR, the US EPA must regulate all of the HAPs emitted by these generating units. Compliance with the MACT standards will be required three years after the effective date of the final regulations. Until the US EPA's regulations are finalized, EMG cannot determine whether the actions it is taking to comply with other legal requirements (including the CPS) will be sufficient to address its obligations under the new HAPs regulations.

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 will be included in calendar year 2016).

Midwest Generation installed required carbon injection equipment on all operating units in 2009 to achieve the necessary mercury reductions. Capital expenditures relating to these controls were $42 million. Midwest Generation will 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. The IEPA granted Midwest Generation a construction permit to install a cold side electrostatic precipitator on Unit 7 in November 2010.

Pennsylvania

Until Pennsylvania passes new legislation authorizing the adoption of mercury regulations or the US EPA finalizes a revised HAPs regulation that includes mercury limits, the Homer City plant 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 the continued implementation and enforcement of the rule.

Ozone and Particulates

National Ambient Air Quality Standards

In January 2010, the US EPA proposed a revision to the primary and secondary NAAQS for 8-hour ozone that it had finalized in 2008. The 8-hour ozone standard established in 2008 was 0.075 parts per million. In January 2010, the US EPA proposed establishing a primary 8-hour ozone NAAQS between 0.060 and 0.070 parts per million and a distinct secondary standard to protect sensitive vegetation and ecosystems. The US

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EPA is expected to finalize the revision to the ozone NAAQS by July 2011. It is expected that once the US EPA finalizes the revised ozone NAAQS, it will propose a second Transport Rule that may further affect electric power generating units. The US EPA is also expected to propose revised fine particulate matter NAAQS in 2011, which could result in further emission reduction requirements in future years.

Illinois

The Illinois SIP for compliance with 1997 8-hour ozone standard was submitted to the US EPA in March 2009. The SIP for fine particulates was submitted to the US EPA in June 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 1997 8-hour ozone standard. However, in March 2009, the PADEP recommended to the US EPA that Indiana County (where the Homer City plant is 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, EMG will not know what specific requirements it will have to meet. However, EMG 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 plant 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 2010.

With respect to fine particulates, in November 2009, the US EPA determined that Indiana County (where the Homer City plant is located) had not attained applicable standards. The PADEP must submit an updated SIP by November 13, 2012. EMG cannot predict the potential effects on the Homer City plant of changes to the SIP.

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 SIPs 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 would result in the imposition of a FIP. Because the Four Corners plant is located on the Navajo Reservation there is no applicable SIP and the plant will be subject only to a FIP.

In relation to Four Corners, the US EPA issued its proposed FIP in October 2010. The proposed FIP would require the installation of SCR pollution control equipment by approximately 2016 on all Four Corners units. In November 2010, SCE and APS entered into an agreement for the sale of SCE's Four Corners interest to APS, subject to regulatory approvals and other conditions. A final FIP is expected in 2011. Due to the investment constraints of SB 1368, the California law on GHG emission performance standards discussed above in " Climate Change Regional Initiatives and State Legislation," SCE does not expect to be a Four Corners participant after the 2016 expiration of the current participant agreements and does not expect to participate in any investment in Four Corners SCRs. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment" for more information on the sale of SCE's interest in Four Corners.

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Illinois and Pennsylvania

Beginning on December 31, 2009 Illinois and Pennsylvania became subject to a two-year deadline after which a FIP (which has not yet been proposed) will govern related emission issues. Pennsylvania submitted its proposed SIP revisions to the US EPA in December 2010 and Illinois is has prepared proposed revisions to its SIP and is expected to submit them to the US EPA in 2011. Illinois proposes that the emission reductions that the Midwest Generation plants will be required to make pursuant to the CPS, discussed above in "Nitrogen Oxide and Sulfur Dioxide Illinois," satisfy the BART requirement. Pennsylvania also proposes that the existing particulate matter emission limits on the Homer City plant, as well as the plant's participation in the CAIR, will satisfy the BART requirement in that state.

New Source Review Requirements

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 NSR 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. The US EPA has filed enforcement actions against Homer City and Midwest Generation alleging NSR violations. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

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, including information about Four Corners' capital projects from 1990 to the present. SCE understands that in other cases the US EPA has utilized responses to similar Section 114 letters to examine whether power plants have triggered NSR requirements under the CAA. In May 2010, four environmental organizations (Dine CARE, National Parks Conservation Association, Sierra Club, and To Nizhoni Ani) served SCE and the other Four Corners owners with a notice of intent to sue under the CAA alleging violations of NSR requirements. The US EPA has not initiated any NSR enforcement-related proceedings with respect to Four Corners. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment," for more information on the sale of SCE's interest in Four Corners.

Water Quality

Clean Water Act

Regulations under the federal Clean Water Act govern critical parameters at generating facilities, such as the temperature of effluent discharges and the location, design and construction of cooling water intake structures at generating facilities. The US EPA is rewriting these regulations following a 2009 U.S. Supreme Court decision holding that the US EPA may consider, but is not required to use, a cost-benefit analysis for this purpose. The Supreme Court set a deadline of March 2011 for draft regulations, which are to be finalized by July 2011.

Because there are no defined compliance targets absent a new rule, EMG and SCE are reviewing a wide range of possible control technologies. A new rule could have a material impact on EMG and SCE, but neither EMG nor SCE can determine the financial impact until the final compliance criteria have been published.

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

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 May 2010 the California State Water Resources Control Board issued a final policy, which establishes closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like SCE's San Onofre and many of the existing fossil-fueled power plants along the California coast. The final policy, which took effect on October 1, 2010, requires an independent engineering study to be completed prior to the fourth quarter of 2013 regarding the feasibility of compliance by California's two

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coastal nuclear power plants, which may result in significant capital expenditures at San Onofre and may affect its operations. The policy could 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. The policy may also significantly impact SCE's ability to procure generating capacity from fossil-fuel plants that use ocean water in once-through cooling systems, system reliability and the cost of electricity if other coastal power plants in California are forced to shut down or limit operations.

Illinois

Midwest Generation is a party to an administrative proceeding before the Illinois Pollution Control Board ("PCB") to determine whether more stringent thermal and effluent water quality standards for the Chicago Area Waterway System and Lower Des Plaines River, which supply cooling water to Midwest Generation's Fisk, Crawford, Will County and Joliet Stations, will be implemented. The rule, if implemented, is expected to affect the manner in which those stations use water for station cooling. 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.

Coal Combustion Wastes

US EPA regulations currently classify coal ash and other coal combustion residuals as solid wastes that are exempt from hazardous waste requirements. This classification enables beneficial uses of coal combustion residuals, such as for cement production and fill materials. Midwest Generation currently provides a portion of its coal combustion residuals for beneficial uses.

In June 2010, the US EPA published proposed regulations relating to coal combustion residuals. Two different proposed approaches are under consideration. The first approach, under which the US EPA would list these residuals as special wastes subject to regulation as hazardous wastes, could require EMG and SCE to incur additional capital and operating costs without assurance that the additional costs could be recovered. For SCE, to the extent such expenditures are for long-term extended operation of Four Corners, SCE does not expect to participate in any such expenditures consistent with SB 1368, the California law on GHG emission performance standards (see " Climate Change Regional Initiatives and State Legislation" above for a description of SB 1368). The second approach, under which the US EPA would regulate these residuals as nonhazardous wastes, would establish minimum technical standards for units that are used for the disposal of coal combustion residuals, but would allow procedural and enforcement mechanisms (such as permit requirements) to be exclusively a matter of state law. Many of the proposed technical standards are similar under both proposed options, but the second approach would not require the retrofitting of landfills used for the disposal of coal combustion residuals.

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ITEM 1A. RISK FACTORS

RISKS RELATING TO EDISON INTERNATIONAL

Edison International's subsidiaries are 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 NRC 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.

EMG'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. 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. EMG in the course of its business must obtain and periodically renew licenses, permits and approvals for its facilities. The FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, where it determines that potential market power might exist and that the public interest requires mitigation. 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.

This extensive governmental regulation creates significant risks and uncertainties for Edison International's business. Existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to SCE, EMG or their facilities or operations in a manner that may have a detrimental effect on Edison International's business or result in significant additional costs.

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 and frequently changing environmental regulations and permitting requirements that involve significant and increasing costs and substantial uncertainty. 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 adoption of laws and regulations to implement greenhouse gas controls could adversely affect operations, particularly of the coal-fired plants. Other environmental laws, particularly with respect to air emissions, disposal of ash, wastewater discharge, and cooling water systems, are also generally becoming more stringent. The continued operation of SCE and EMG facilities, particularly the coal-fired facilities, is expected to require substantial capital expenditures for environmental controls or cessation of operations. Cessation of operations of such coal-fired plants at EMG would have a material adverse effect. SCE and EMG may also be exposed to risks arising from past, current or future contamination at its former or existing facilities or with respect to off site waste disposal sites that have been used in its operations. Current and future state laws and regulations in California also could increase the required amount of power that must be procured from renewable resources. For further discussion of the environmental regulations applicable to Edison International and its subsidiaries, see "Item 1. Business Environmental Regulation of Edison International and Subsidiaries."

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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 results depend upon its ability to recover its costs in a timely manner from its customers through regulated rates.

SCE's ongoing financial results depend 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 results also depend on its ability to earn through the rates it is allowed to charge an adequate return on capital, including long-term debt and equity. SCE's capital investment plan, California's commitment to renewable power, increasing environmental regulations, sensitivity to increasing natural gas costs and moderating demand, collectively place continuing upward pressure on customer rates. If SCE is unable to obtain a sufficient rate increase or 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. For further information on SCE's rate requests, see "Edison International Overview SCE Rate Cases" in the MD&A.

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, including exposure to commodity price and counterparty credit risks. 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.

SCE may not be able to hedge its risk for commodities on economic 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 operations. See "SCE: Market Risk Exposures" in the MD&A.

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 is engaged in one of the largest infrastructure investment programs in its history, which involves multiple large-scale projects in multiple locations. This substantial increase in activity from SCE's historical levels elevates the operational risks and the need for superior execution in its activities. SCE's financial condition and results of operations could be materially adversely affected if it is unable to successfully manage these risks as well as the risks inherent in operating and improving its facilities, the operation of which can be hazardous. SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, system limitations and degradation, failure or breaches of critical information technology systems and interruptions in necessary supplies. See "SCE: Liquidity and Capital Resources Capital Investment Plan" in the MD&A.

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

Continued NRC scrutiny of regulatory and performance issues at San Onofre may result in additional corrective actions that will increase operations and maintenance costs or require additional capital expenditures.

As discussed in "Item 1. Business Southern California Edison Company Regulation Nuclear Power Plant Regulation," the NRC is conducting additional inspections and public meetings to assess the corrective actions taken at San Onofre in connection with various regulatory and performance issues. This scrutiny may result in SCE being required to take additional corrective actions and incur increased operations and maintenance expenses or new capital expenditures. If SCE is unable to take effective corrective actions, the NRC has the authority to impose fines or shut down a unit, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved.

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 nuclear incident liability claims were to exceed $375 million, the remaining amount would be made up from contributions of approximately $12.2 billion made by all of the nuclear facility owners in the U.S., up to an aggregate total of $12.6 billion. There is no assurance that the CPUC would allow SCE to recover the required contribution made in the case of a nuclear incident claim(s) that exceeded $375 million. If this public liability limit of $12.6 billion is insufficient, federal law contemplates that additional funds may be appropriated by Congress. There can be no assurance of SCE's ability to recover uninsured costs in the event the additional federal appropriations are insufficient.

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

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.

SCE's insurance coverage for wildfires arising from its ordinary operations may not be sufficient and Edison International may not be able to obtain sufficient insurance on SCE's behalf for such occurrences.

Edison International has been experiencing increased costs and difficulties in obtaining insurance coverage for wildfires that could arise from SCE's ordinary operations. In addition, the insurance Edison International has obtained on SCE's behalf for wildfire liabilities may not be sufficient. Uninsured losses and increases in the cost of insurance may not be recoverable in customer rates. A loss which is not fully insured or cannot be recovered in customer rates could materially and adversely affect Edison International's and SCE's financial condition and results of operations. Furthermore, insurance for wildfire liabilities may not continue to be available at all or at rates or on terms similar to those presently available to Edison International. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 10. Regulatory and Environmental Developments."

Financing Risks

As a capital intensive company, 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 would be adversely affected.

SCE regularly accesses capital markets to finance its activities and is expected to do so by its regulators as part of its obligation to serve as a regulated utility. SCE's needs for capital for its ongoing infrastructure investment program are substantial. SCE's ability to arrange financing as well as its ability to refinance debt

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and make scheduled payments of principal and interest 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. SCE's failure to obtain additional capital from time to time would have a material adverse effect on SCE's liquidity and operations. See "SCE: Liquidity and Capital Resources Capital Investment Plan" and "SCE: Liquidity and Capital Resources Historical Segment Cash Flows" in the MD&A.

RISKS RELATING TO EMG

Liquidity Risks

EME and its subsidiaries have significant cash requirements and limited sources of capital.

At December 31, 2010, EME had corporate cash and cash equivalents of $615 million and $484 million of available borrowing capacity under its $564 million credit facility maturing in June 2012 and Midwest Generation had cash and cash equivalents of $295 million and $497 million of available borrowing capacity under its $500 million credit facility maturing in June 2012.

As of December 31, 2010, EME's consolidated debt was approximately $4.5 billion. EME's subsidiaries had $2.9 billion of long-term, power plant lease obligations that are due over a period ranging up to 24 years. Compliance with current and forthcoming environmental requirements will add to EME's near-term liquidity needs.

EME's and Midwest Generation's below-investment grade credit status may limit their ability to extend or replace credit facilities, including those maturing in 2012, should they choose to do so, and the terms and conditions of any refinancing could be substantially less favorable than those in the current credit facilities, depending on market conditions. In the case of a further downgrade, EME expects that these negative effects would become more pronounced. If EME's credit facilities are not extended or replaced, or if cash flow and other means for assuring liquidity are unavailable or insufficient, EME may be unable to complete environmental improvements at its coal plants (which in turn could lead to unit shutdowns) or to provide credit support for contracts for power and fuel related to merchant activities. The terms of EME's and its subsidiaries' debt instruments may restrict EME's subsidiaries ability to sell assets or incur secured indebtedness, and EME's subsidiaries' debt instruments may limit EME's ability to seek additional capital, or restructure or refinance debt to satisfy liquidity needs. For further discussion of EME's liquidity needs, see "EMG: Liquidity and Capital Resources" in the MD&A.

EME depends upon tax-allocation payments from Edison International to meet its obligations. EME receives these payments only if, and only to the extent that, Edison International is able to utilize tax losses and credits generated by EME.

EME receives tax-allocation payments for tax losses when and to the extent that the consolidated Edison International group generates sufficient taxable income to be able to utilize EME's consolidated tax losses and credits in the consolidated income tax returns for Edison International and its subsidiaries. The timing of certain tax-allocation payments was delayed in 2010 as a result of the Small Business Jobs Act and the 2010 Tax Relief Act, because Edison International was not able to fully utilize EME's consolidated tax losses and credits. Tax-allocation payments to EME may be further delayed until tax benefits are fully utilized by Edison International on a consolidated basis, which may take several years as a result of these new tax laws. See "Edison International Overview Bonus Depreciation Impact on Edison International" in the MD&A for further discussion.

These arrangements are subject to the terms of the tax-allocation and payment agreements among Edison International, EME and other Edison International subsidiaries. The agreements under which EME receives tax-allocation payments may be terminated by the immediate parent company at any time, by notice given before the first day of the first year with respect to which the termination is to be effective. However, termination does not relieve any party of any obligations with respect to any tax year beginning prior to the notice. See "EMG: Liquidity and Capital Resources Intercompany Tax-Allocation Agreement" in the MD&A.

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Regulatory and Environmental Risks

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

All of Midwest Generation's Illinois coal-fired electric generating units are subject to the CPS. Capital expenditures relating to controls contemplated by the CPS are expected to be significant and could make some units uneconomic to maintain or operate. Midwest Generation may ultimately decide to comply with CPS requirements by shutting down units rather than making improvements. Unit shutdowns could have an adverse effect on EMG's business, results of operation and financial condition. For more information about the CPS requirements and Midwest Generation's plans for compliance, see "Item 1. Business Environmental Matters and Regulations Air Quality Nitrogen Oxide and Sulfur Dioxide Illinois."

Market Risks

EMG has substantial interests in merchant energy power plants which are subject to market risks related to wholesale energy prices because they operate without long-term power purchase agreements. Wholesale energy prices have substantially declined in recent years.

EMG'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. 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 coal plants, EMG has concentrated exposure to market conditions and fluctuations in PJM. Prices for power have declined significantly in recent years as a result of increased use of demand response technology, changes in final demand for power during the economic slowdown, and technological developments that have permitted the exploitation of natural gas shale reserves in a way that has resulted in substantial declines in market prices for natural gas which supplies power plants that compete with EMG's coal plants.

Market prices of energy, capacity and ancillary services sold from these power plants are influenced by multiple factors beyond EMG's control, and thus there is considerable uncertainty whether or when current depressed prices will recover or whether EMG can effectively hedge the risks involved on economic terms. EMG'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. The effectiveness of EMG's hedging activities may depend on the amount of credit available to post collateral, either in support of performance guarantees or as cash margin, and liquidity requirements may be greater than EMG anticipates or will be able to meet. EMG cannot provide assurance that its hedging strategies will successfully mitigate market risks. For more detail on these matters, see "EMG: Market Risk Exposures Commodity Price Risk" in the MD&A.

EMG's financial results can be affected by changes in prices, transportation cost, and supply interruptions related to fuel, sorbents, and other commodities used for power generation and emission controls.

In addition to volatile power prices, EMG's business is subject to changes in the cost of fuel, sorbents, and other commodities used for power generation and emission controls, and in the cost of transportation. These costs can be volatile and are influenced by many factors outside of EMG's control. The price at which EMG can sell its energy may not rise or fall at the same rate as a corresponding rise or fall in commodity costs. Operations at the coal plants are dependent upon the availability and affordability of coal which is available only from a limited number of suppliers and which, in the case of Midwest Generation, is transported by rail under a long-term transportation contract that will expire in 2011.

All of these factors may have an adverse effect on EMG's financial condition and results of operations. See "EMG: Market Risk Exposures Commodity Price Risk" in the MD&A.

Competition could adversely affect EMG's business

EMG 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, greater ability to withstand

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losses, larger staffs or more experience than EMG. 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 EMG's ability to compete effectively in the markets in which those entities operate. Newer plants owned by EMG's competitors are often more efficient than EMG's facilities and may also have lower costs of operation. Over time, some of EMG's merchant facilities may become obsolete in their markets, or be unable to compete with such plants.

Operating Risks

EMG's development projects may not be successful.

EMG'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. EMG may be required to spend significant amounts for preliminary engineering, permitting, fuel supply, resource exploration, legal and other expenses before it can determine whether a project is feasible, economically attractive, or capable of being built. As a result of these risks, EMG may not be successful in developing new projects, or the timing of such development may be delayed beyond the date that equipment is ready for installation, in which case EMG may be required to incur material equipment and/or material costs with no deployment plan at delivery. Projects under development may also be adversely affected by delays in construction or equipment deliveries, commissioning delays or performance issues, and agreements with off-takers may contain damages and termination provisions related to failures to meet specified milestones. Due to competing capital needs, EMG's further development of its renewable business will depend upon the availability of third-party equity capital.

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

The operation of power generation facilities is a potentially dangerous activity that involves many operating risks, including transmission disruptions and constraints, equipment failures or shortages, and system limitations, degradation and interruption. EMG's operations are also subject to risks of human performance and workforce capabilities. There can be no assurance that EMG's insurance will be sufficient or effective under all circumstances or protect against all hazards to which EMG may be subject, or that insurance coverage will continue to be available on terms similar to those presently available, or at all.

EMG has a number of older facilities with potentially higher risks of failure or outage than an average plant, and EMG has in the past experienced serial defects in certain models of wind turbines deployed at its wind projects.

Uncertainties in EMG's future operations could affect its ability to attract and retain skilled people.

Uncertainties concerning EMG's future operations could affect its ability to attract and retain qualified personnel with experience in the energy industry. If EMG is unable to successfully attract and retain an appropriately qualified workforce, its results of operations will be negatively affected.

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 "Item 1. Business Southern California Edison Company Properties." Properties of EMG are described above under "Edison Mission Group Inc. Properties."

ITEM 3. LEGAL PROCEEDINGS

California Coastal Commission Potential Environmental Proceeding

In May 2010, the California Coastal Commission issued a NOV to SCE, its contractor and certain property owners related to activity on a property that was used for equipment storage related to a nearby SCE electricity line undergrounding construction project. The NOV alleged that SCE, through its contractor, violated the California Coastal Act by removing without the appropriate permits approximately one acre of vegetation from the property, which was located in a protected coastal zone within and adjacent to the City of Newport Beach, California. In the NOV, the Coastal Commission indicated an interest in negotiating a settlement of the alleged violations but no settlement has been reached. The Coastal Act provides for penalties of up to $30,000 per violation, which may be increased by up to $15,000 per day per violation for knowing and intentional violations. SCE has sought indemnification from its contractor for liability associated with the NOV.

For a discussion of other material pending legal proceedings affecting Edison International and its subsidiaries, see "Item 8. Edison International Notes to the Consolidated Financial Statements Note 9. Commitments and Contingencies."

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

EXECUTIVE OFFICERS OF THE REGISTRANT

Executive Officer	Age at December 31, 2010	Company Position
Theodore F. Craver, Jr.	59	Chairman of the Board, President and Chief Executive Officer, Edison International
Robert L. Adler	63	Executive Vice President and General Counsel, Edison International
Polly L. Gault	57	Executive Vice President, Public Affairs, Edison International
W. James Scilacci	55	Executive Vice President, Chief Financial Officer and Treasurer, Edison International
Daryl D. David	56	Senior Vice President, Human Resources, Edison International
Mark C. Clarke	54	Vice President and Controller, Edison International
Ronald L. Litzinger	51	President, SCE
Pedro J. Pizarro	45	President, EMG and EME

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, those officers who have

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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
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
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
Mark C. Clarke	Vice President and Controller, Edison International	August 2009 to present
	Vice President and Controller, EME	January 2003 to July 2009
Ronald J. Litzinger	President, SCE	January 2011 to present
	Chairman of the Board, President and Chief Executive Officer, EMG and EME	April 2008 to December 2010
	Senior Vice President, Transmission and Distribution, SCE	May 2005 to March 2008
Pedro J. Pizarro	President, EMG and EME	January 2011 to present
	Executive Vice President, Power Operations, SCE	April 2008 to December 2010
	Senior Vice President, Power Procurement, SCE	May 2005 to March 2008

1 Munger, Tolles & Olson LLP is a California-based law firm. 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.

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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 18. 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 Parent and Other" and in "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Debit and Credit Agreements." The number of common stockholders of record of Edison International was 45,430 on February 24, 2011. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page of this report. The description of Edison International's equity compensation plans required by Item 201(d) of Regulation S-K is incorporated by reference to "Part III Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" of this report.

Issuer Purchases of Securities

The following table contains information about all purchases of Edison International Common Stock made by or on behalf of Edison International in the fourth quarter of 2010.

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, 2010 to October 31, 2010	568,862	$ 35.84		
November 1, 2010 to November 30, 2010	718,119	$ 37.37		
December 1, 2010 to December 31, 2010	1,022,928	$ 38.64		
Total	2,309,909	$ 37.55		

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

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Comparison of Five-Year Cumulative Total Return

	12/05	12/06	12/07	12/08	12/09	12/10
Edison International	100	107	128	80	90	103
S & P 500 Index	100	116	122	77	97	112
Philadelphia Utility Index	100	120	143	104	114	121

Note: Assumes $100 invested on December 31, 2005 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.

ITEM 6. SELECTED FINANCIAL DATA

Selected Financial Data: 2006 2010

(in millions, except per-share amounts)	2010	2009	2008	2007	2006
Edison International and Subsidiaries					
Operating revenue	$ 12,409	$ 12,361	$ 14,112	$ 12,868	$ 12,169
Operating expenses	$ 10,283	$ 10,963	$ 11,549	$ 10,359	$ 9,680
Income from continuing operations	$ 1,303	$ 952	$ 1,348	$ 1,307	$ 1,273
Net income	$ 1,307	$ 945	$ 1,348	$ 1,305	$ 1,371
Net income attributable to common shareholders	$ 1,256	$ 849	$ 1,215	$ 1,098	$ 1,181
Weighted-average shares of common stock outstanding (in millions)	326	326	326	326	326
Basic earnings (loss) per share:					
Continuing operations	$ 3.83	$ 2.61	$ 3.69	$ 3.34	$ 3.28
Discontinued operations	$ 0.01	$ (0.02)	$	$ (0.01)	$ 0.30
Total	$ 3.84	$ 2.59	$ 3.69	$ 3.33	$ 3.58
Diluted earnings per share	$ 3.82	$ 2.58	$ 3.68	$ 3.31	$ 3.57
Dividends declared per share	$ 1.265	$ 1.245	$ 1.225	$ 1.175	$ 1.10
Total assets	$ 45,530	$ 41,444	$ 44,615	$ 37,523	$ 36,261
Long-term debt	$ 12,371	$ 10,437	$ 10,950	$ 9,016	$ 9,101
Preferred and preference stock of utility	$ 907	$ 907	$ 907	$ 915	$ 915
Common shareholders' equity	$ 10,583	$ 9,841	$ 9,517	$ 8,444	$ 7,709

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.

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

EDISON INTERNATIONAL OVERVIEW

Edison International is a holding company whose operations are conducted through its wholly owned subsidiaries. Its principal wholly owned subsidiaries are SCE, a rate-regulated electric utility that supplies electric energy to an approximately 50,000 square-mile area of southern California; and EMG, a wholly owned competitive power generation company that operates in 12 states.

Highlights of Operating Results

(in millions)	2010	2009	Change	2008
Net Income attributable to Edison International				
SCE	$ 1,040	$ 1,226	$ (186)	$ 683
EMG	224	(395)	619	561
Edison International Parent and Other	(8)	18	(26)	(29)
Edison International Consolidated	1,256	849	407	1,215
Non-Core Items				
Global Settlement				
SCE	95	306	(211)	
EMG[1]	52	(610)	662	
Edison International Parent and Other	28	50	(22)	
SCE tax impact of health care legislation	(39)		(39)	
SCE regulatory items		46	(46)	(49)
EMG write-off of capitalized costs	(24)		(24)	
EMG discontinued operations	4	(7)	11	
Total non-core items	116	(215)	331	(49)
Core Earnings				
SCE	984	874	110	732
EMG	192	222	(30)	561
Edison International Parent and Other	(36)	(32)	(4)	(29)
Edison International Consolidated	$ 1,140	$ 1,064	$ 76	$ 1,264

1 Includes termination of Edison Capital's cross-border leases in 2009 and state tax impact of the Global Settlement with the IRS.

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 are 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: exit activities, including lease terminations, sale of certain assets, early debt extinguishment costs and other activities that are no longer continuing; asset impairments and certain tax, regulatory or legal settlements or proceedings.

SCE's 2010 core earnings increased $110 million primarily due to higher operating income and capitalized financing costs (AFUDC), both driven by higher rate base growth, and lower income tax expense. The lower tax expense in 2010 includes a change in the method of tax accounting for asset removal costs primarily related to SCE's infrastructure replacement program.

EMG's 2010 core earnings decreased $30 million from 2009 primarily from higher plant maintenance costs in 2010 due to scheduled outages in EMG's merchant power plants, unrealized losses in 2010 compared to gains in 2009, higher income tax expense partially offset by higher energy trading revenues.

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Edison International Parent and Other 2010 core losses increased from 2009 primarily due to higher interest and general and administrative costs.

Consolidated non-core items for Edison International included:

- An after tax earnings benefit of $175 million recorded in 2010 relating to the California impact of the federal Global Settlement resulting from acceptance by the California Franchise Tax Board of tax positions finalized with the IRS in 2009 and a revision to interest recorded on the federal Global Settlement. In 2009, Edison International recorded an after-tax earnings charge of $254 million related to the Global Settlement with the IRS and termination of EMG's cross-border leases ($920 million pre-tax loss). For further discussion of the Global Settlement, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 7. Income Taxes."

- An after tax earnings charge of $39 million recorded in 2010 to reverse previously recognized federal tax benefits eliminated by the recently enacted federal health care legislation. The new health care law eliminated the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies.

- An after-tax earnings charge of $24 million ($40 million pre-tax) recorded in the fourth quarter of 2010 resulting from the write-off of capitalized engineering and other costs for air emissions control technology that is not currently being pursued for use at the Powerton Station. These activities were previously suspended as Midwest Generation pursued testing and evaluation of the use of a dry sorbent injection system using Trona or similar sorbents which is expected to require lower capital costs. The Illinois EPA recently issued a construction permit to authorize installation of a dry sorbent injection system, which Midwest Generation currently expects to use if this project is undertaken. For further discussion, see " Environmental Developments Midwest Generation Environmental Compliance Plans and Costs" below.

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

See "SCE: Results of Operations" for discussion of SCE results of operations, including a comparison of 2009 results to 2008. Also, see "EMG: Results of Operations" for discussion of EMG results of operations, including a comparison of 2009 results to 2008.

Management Overview of SCE

During 2009 and 2010, SCE focused on the execution of its capital investment program. Capital expenditures under the program were primarily for: upgrading, maintaining and expanding SCE's transmission and distribution system; extending the useful life of generation assets; and installing smart meters. Total capital expenditures were $2.9 billion in 2009 and $3.8 billion in 2010. A description of SCE's capital program for 2011 2014 and status of major rate cases is discussed below.

Capital Program

SCE's capital program for 2011 2014 is focused primarily in the following areas:

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

- Upgrading and constructing new transmission lines for system reliability and increased access to renewable energy, including the Tehachapi, Devers-Colorado River, Eldorado-Ivanpah, Red Bluff and Alberhill projects.

Generation investments for nuclear and hydro-electric plant betterment projects and general facilities and technology needs.

Installing "smart" meters in households and small businesses, referred to as EdisonSmartConnect . Through 2010, SCE installed 2 million smart meters and plans to complete installation of the remaining 3.3 million meters during 2011 and 2012.

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SCE forecasts capital expenditures in the range of $15.6 billion to $17.5 billion for 2011 2014. The rate of actual capital spending may be affected by permitting, regulatory, market and other factors as discussed further under "SCE: Liquidity and Capital Resources Capital Investment Plan." SCE plans to utilize cash generated from its operations, tax benefits and issuance of additional debt and preferred equity to fund its capital needs.

SCE Rate Cases

2012 CPUC General Rate Case

On November 23, 2010, SCE filed its 2012 GRC application requesting a 2012 base rate revenue requirement of $6.3 billion. After considering the effects of sales growth, SCE's request would be an $866 million increase in 2012 base rate revenue. The requested revenue requirement increase is driven by investments in capital projects to maintain system reliability and accommodate customer load growth, as well as an increase in operation and maintenance expenses primarily for capital-related projects, information technology, insurance premiums and pension contributions. If the CPUC approves the requested rate increase, the system average rate increase over base rate and total revenue requirement is estimated to be 16.2% and 7.6%, respectively. The increase excludes the impact of rate changes not associated with the CPUC GRC, such as rates to recover purchased power. The application also proposes a ratemaking mechanism that would result in 2013 and 2014 incremental base rate revenue requirement increases, net of sales growth of $246 million and $527 million, respectively, driven by the same reasons.

SCE is required to update its 2012 GRC request to reflect, among other items, the impacts of governmental and legislative actions. As part of this update, SCE expects the base rate revenue requirement will be reduced to reflect bonus depreciation (discussed below in " Bonus Depreciation Impact on Edison International"). Bonus depreciation is an acceleration of future tax deductions which results in a reduction to rate base. SCE intends to update its 2012 GRC request after the IRS issues final regulations.

The current schedule anticipates a final decision on SCE's 2012 GRC by the end of 2011. SCE cannot predict the revenue requirement the CPUC will ultimately authorize or when a final decision will be adopted.

FERC 2010 Rate Case

In February 2011, the FERC approved a settlement agreement in SCE's 2010 FERC rate case that provides a FERC retail base revenue requirement of $490 million, an increase of $42 million, or 9.4%, over the 2009 FERC base revenue requirement. The increased revenue requirement is primarily due to an increase in transmission capital investments and will be retroactive to March 1, 2010. As of December 31, 2010, SCE had collected revenue, subject to refund, of $58 million that will be refunded to ratepayers. SCE did not previously recognize revenue for the amount that will be refunded.

NRC Oversight of San Onofre

SCE continues to apply increased management focus and other resources to San Onofre to address regulatory and performance issues identified by the NRC (see "Item 1. Business Southern California Edison Company Regulation Nuclear Power Plant Regulation" for further discussion).

Management Overview of EMG

EMG's competitive power generation business primarily consists of the generation and sale into the PJM market of energy and capacity from its approximately 7,000 megawatts of coal-fired power plants. The profitability of these operations is expected to decline significantly in 2011 as a result of lower realized energy prices (largely driven by the expiration of hedge contracts) and higher fuel costs. In addition, the profitability of EMG's Midwest Generation plants is expected to be adversely affected in 2012 by a decline in capacity prices (projected to begin in June 2012) and higher rail transportation costs (due to the expiration at the end of 2011 of a favorable long-term rail contract). For discussion of energy and fuel price risks, see "EMG: Market Risk Exposures Commodity Price Risk" and "Item 1A. Risk Factors Risks Relating to EMG Market Risks." As a result of the projected decrease in profitability of EMG's merchant activities, EMG may incur net losses during 2011 and in subsequent years unless energy prices recover or its costs decline.

At December 31, 2010, EMG and its subsidiaries had $1.1 billion in cash and cash equivalents and $981 million of liquidity available from credit facilities that expire in 2012. EMG's principal subsidiary, EME, had $3.7 billion of notes outstanding at December 31, 2010, $500 million of which mature in 2013. EMG business plans are focused on operating effectively through the current commodity price cycle and on environmental compliance and renewable energy plans as described below.

Environmental Developments

Midwest Generation Environmental Compliance Plans and Costs

During 2010, Midwest Generation continued its permitting and planning activities for NO_x and SO_2 controls to meet the requirements of the CPS. Midwest Generation has received all necessary permits from the Illinois EPA to allow the installation of SNCR technology on multiple units to meet the NO_x portion of the CPS. In November 2010 and February 2011, the Illinois EPA issued construction permits authorizing Midwest Generation to install a dry sorbent injection system using Trona or its equivalent at the Waukegan generating station's Unit 7 and Units 5 and 6 at the Powerton Station. The permit for Unit 7 for the Waukegan Station also authorizes Midwest Generation to convert the existing electrostatic precipitator to a cold-side design which will improve removal efficiency of particulate matter to satisfy the particulate control requirements of the CPS.

Testing of dry scrubbing using Trona on select Midwest Generation units has demonstrated significant reductions in SO_2 emissions. Use of this technology in conjunction with low sulfur coal is expected to require substantially less capital and time than the use of spray dryer absorber technology, but would likely result in higher ongoing operating costs and may consequently result in lower dispatch rates and competitiveness of Midwest Generation's plants, depending on competitors' costs.

Based on work to date, Midwest Generation estimates the cost of retrofitting all units, using dry scrubbing with sodium-based sorbents to comply with CPS requirements for SO_2 emissions, and the associated upgrading of existing particulate removal systems, would be approximately $1.2 billion in 2010 dollars. If these projects are undertaken, these expenditures would be incurred through 2018.

Decisions regarding whether or not to proceed with the above projects or other approaches to compliance remain subject to a number of factors, such as market conditions, regulatory and legislative developments, and forecasted commodity prices and capital and operating costs applicable at the time decisions are required or made. Midwest Generation could also elect to shut down units, instead of installing controls, to be in compliance with the CPS. Therefore, decisions about any particular combination of retrofits and shutdowns it may ultimately employ also remain subject to conditions applicable at the time decisions are required or made. Due to existing uncertainties about these factors, Midwest Generation intends to defer final decisions about particular units for the maximum time available. Accordingly, final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital that is budgeted may not occur until 2012 for some of the units and potentially later for others. Preconstruction engineering and initial construction work on a project may occur in 2011 in advance of a final decision to continue or complete the project.

Homer City Environmental Issues and Capital Resource Limitations

Homer City may be required to install additional environmental equipment on Units 1 and 2 to comply with environmental regulations under the Transport Rule. Homer City projects that if SO_2 reduction technology becomes required, it may need to make capital commitments for such equipment several years in advance of the effective date of such requirements. Homer City continues to review technologies available to reduce SO_2 and mercury emissions and to monitor developments related to hazardous pollutants and other environmental regulations. The timing, selection of technology and required capital costs remain uncertain. The installation of environmental compliance equipment will be dependent on lessor decisions regarding the funding of these expenditures. 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. EME has no legal

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obligation to provide funding. Accordingly, final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital have not been made.

EMG Renewable Program

At December 31, 2010, EMG had a development pipeline of potential wind projects with projected installed capacity of approximately 3,600 MW and had four projects totaling 480 MW under construction. EMG anticipates that these projects will achieve commercial operation in 2011. In addition to the projects under construction at December 31, 2010, EMG expects the 55 MW Pinnacle project in West Virginia will commence construction in 2011 with anticipated commercial operation in 2011. The pace of additional growth in EMG's renewable program will be subject to the availability of third-party capital.

Bonus Depreciation Impact on Edison International

The Small Business Jobs Act of 2010 and The Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 ("2010 Tax Relief Act") extended 50% bonus depreciation for qualifying property through 2012 and created a new 100% bonus depreciation for qualifying property placed in service between September 9, 2010 and December 31, 2011. In addition to the update of the 2012 GRC discussed above, these provisions are expected to:

- result in a consolidated net operating loss for federal income tax purposes for 2010 and 2011;
- provide additional cash flow benefits during 2011 to SCE of approximately $550 million;
- delay tax-allocation payments to EMG until tax benefits are fully utilized by Edison International on a consolidated basis which may take several years; and
- eliminate income tax benefits from the domestic production activities deduction (also known as Section 199 deductions) of $16 million in 2011. The negative impact on 2010 net income was $15 million from recapture of 2008 Section 199 deductions realized in prior years resulting from the carry back of net operating losses.

The impact on cash flow represents an acceleration of tax benefits that would have otherwise been deductible over the life of the qualifying assets.

Environmental Regulation Developments

For a discussion of environmental regulation developments regarding Greenhouse Gas Regulation, the Transport Rule, Hazardous Air Pollutant Regulations, California Once-Through Cooling issues and Coal Combustion Wastes, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 10. Regulatory and Environmental Developments."

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SOUTHERN CALIFORNIA EDISON COMPANY

RESULTS OF OPERATIONS

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

- Utility earning activities representing CPUC and FERC-authorized base rates, including an authorized reasonable return, and CPUC-authorized incentive mechanisms; and

- Utility cost-recovery activities representing CPUC-authorized balancing accounts which allow for recovery of costs incurred or provide for mechanisms to track and recover or refund differences in forecasted and actual amounts.

Utility earning activities include base rates that are designed to recover forecasted operation and maintenance costs, certain capital-related carrying costs, interest (including interest on balancing accounts), taxes and a return, including the return on capital projects recovered through balancing account mechanisms. Differences between authorized amounts 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 that 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), certain operation and maintenance expenses, and depreciation expense related to certain projects. There is no return for cost-recovery expenses.

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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.

	2010			2009			2008		
(in millions)	**Utility Earning Activities**	**Utility Cost-Recovery Activities[1,2]**	**Total Consolidated**	**Utility Earning Activities**	**Utility Cost-Recovery Activities[1,2]**	**Total Consolidated**	**Utility Earning Activities**	**Utility Cost-Recovery Activities[1,2]**	**Total Consolidated**
Operating revenue	$ 5,606	$ 4,377	$ 9,983	$ 5,303	$ 4,662	$ 9,965	$ 4,856	$ 6,392	$ 11,248
Fuel and purchased power		3,293	3,293		3,472	3,472		5,245	5,245
Operations and maintenance	2,271	1,020	3,291	2,111	1,043	3,154	2,079	934	3,013
Depreciation decommissioning and amortization	1,213	60	1,273	1,124	54	1,178	1,055	59	1,114
Property taxes and other	260	3	263	244		244	232		232
Gain on sale of assets		(1)	(1)		(1)	(1)		(9)	(9)
Total operating expenses	3,744	4,375	8,119	3,479	4,568	8,047	3,366	6,229	9,595
Operating income	1,862	2	1,864	1,824	94	1,918	1,490	163	1,653
Net interest expense and other	(330)	(2)	(332)	(298)		(298)	(414)	7	(407)
Income before income taxes	1,532		1,532	1,526	94	1,620	1,076	170	1,246
Income tax expense	440		440	249		249	342		342
Net income	1,092		1,092	1,277	94	1,371	734	170	904
Net income attributable to noncontrolling interest					94	94		170	170
Dividends on preferred and preference stock	52		52	51		51	51		51
Net income available for common stock	$ 1,040	$	$ 1,040	$ 1,226	$	$ 1,226	$ 683	$	$ 683
Core Earnings[3]			$ 984			$ 874			$ 732
Non-Core Earnings:									
Global tax settlement			95			306			
Tax impact of health care legislation			(39)						
Regulatory items						46			(49)
Total SCE GAAP Earnings			$ 1,040			$ 1,226			$ 683

1 Effective January 1, 2010, SCE deconsolidated the Big 4 projects and therefore these projects are no longer reflected in 2010 activities (see "Item 8. Edison International Notes to Consolidated Financial Statements Note 3. Variable Interest Entities" for further discussion).

2

Effective July 1, 2009, SCE transferred Mountainview Power Company, LLC to SCE (see "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment" for further discussion). As a result of the transfer and for comparability purposes, Mountainview's 2009 and 2008 activities were reclassified from cost-recovery activities to utility earning activities consistent with the 2010 regulatory recovery mechanism.

[3] See use of Non-GAAP financial measures in "Edison International Overview Highlights of Operating Results."

Utility Earning Activities

2010 vs. 2009

Utility earning activities were primarily affected by the following:

- Higher operating revenue of $303 million primarily due to the following:
  - $190 million increase related to the implementation of SCE's 2009 GRC (effective January 1, 2009) which authorized an increase of approximately $205 million ($15 million of which is reflected in utility cost-recovery activities) from SCE's 2009 revenue requirement.
  - $55 million increase in FERC-related revenue, primarily due to the implementation of SCE's 2010 and 2009 FERC rate cases effective March 1, 2010 and March 1, 2009, respectively (see

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"Edison International Overview SCE Rate Cases 2010 FERC Rate Case" for further discussion).

$55 million increase related to capital-related revenue requirements recovered through CPUC-authorized mechanisms outside of the GRC process primarily related to the steam generator replacement project and the EdisonSmartConnect™ project.

Higher operation and maintenance expense of $160 million primarily due to the following:

$75 million of higher expenses to support company growth programs, including new information technology system requirements and facility maintenance.

$45 million of higher transmission and distribution expenses to support system reliability and infrastructure replacement, right of way costs; preventive maintenance work, technical training and line clearing.

$15 million of higher generation expenses primarily from a $25 million increase from the San Onofre Unit 2 and 3 scheduled outages, including $10 million of additional work identified during the Unit 2 scheduled outage, and a $10 million increase primarily due to overhaul and outage costs at Four Corners. These increases were partially offset by a $20 million decrease resulting from 2009 scheduled outages at the Mountainview power plant.

SCE completed the replacement of the steam generators at San Onofre Unit 2 and Unit 3 in April 2010 and February 2011, respectively. During the San Onofre Unit 2 scheduled outage, SCE identified and completed additional work unrelated to the steam generator replacement that resulted in increased operation and maintenance expense and extended the outage beyond SCE's initial estimated timeframe. The San Onofre Unit 3 outage was briefly extended beyond SCE's initial estimated timeframe.

The CPUC previously adopted a mechanism establishing thresholds for review and recovery of SCE's incurred capital costs for the steam generator replacements. Based on preliminary cost information, SCE does not expect a reasonableness review will be required. SCE will file an application with the CPUC setting forth its final costs and compliance with the adopted mechanism.

$15 million of higher expense related to general liability and property insurance due to higher premiums for wildfire coverage.

Higher depreciation expense of $89 million primarily related to increased capital expenditures, including capitalized software costs.

Higher net interest expense and other of $32 million primarily due to:

Lower other income of $19 million primarily related to a decrease in AFUDC equity earnings due to the transfer of the Mountainview power plant to utility rate base in the third quarter of 2009 partially offset by an increase in AFUDC equity resulting from a higher capitalization rate and level of construction in progress associated with SCE's capital expenditure plan.

Higher interest expense of $7 million primarily due to higher outstanding balances on long-term debt.

See " Income Taxes" below for discussion of higher income taxes during 2010 compared to the same period in 2009.

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2009 vs. 2008

Utility earning activities were primarily affected by:

- Higher operating revenue of $447 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 implementation of SCE's 2009 FERC approved rate case settlement effective March 1, 2009.
  - $25 million decrease due to the presentation of 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 consistent with the balancing account ratemaking treatment authorized in SCE's 2009 GRC.
- Higher operation and maintenance expenses of $32 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 (See "Item 1. Business Southern California Edison Company 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.
  - $175 million decrease due to presentation of medical, dental and vision expenses and SCE's share of Palo Verde operations and maintenance expenses, which beginning in 2009 are reflected in cost-recovery activities consistent with the balancing account ratemaking treatment authorized in SCE's 2009 GRC.
- Higher depreciation expense of $69 million primarily resulting from increased capital expenditures including capitalized software costs.
- Lower net interest expense and other of $116 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. These decreases were partially offset by an $8 million increase in donations.

Higher other income of $61 million due to an increase in AFUDC equity earnings primarily resulting from a $50 million one-time gain resulting from the transfer of the Mountainview power plant to utility rate base authorized in SCE's 2009 GRC and a $12 million increase resulting from a higher level of construction work in progress associated with SCE's capital expenditure program.

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.

See " Income Taxes" below for discussion of lower income taxes during 2009 compared to the same period in 2008.

Utility Cost-Recovery Activities

2010 vs. 2009

Utility cost-recovery activities excludes the impact of the consolidation of the Big 4 projects in 2009 for comparability purposes. The following amounts were excluded for 2009: $370 million for purchased power expense to reflect the elimination of sales between the VIEs and SCE; $368 million for fuel expense; and $94 million for operation and maintenance expense. Utility cost-recovery activities were primarily affected by:

- Lower purchased power expense of $191 million related to: lower realized losses on economic hedging activities ($156 million in 2010 compared to $344 million in 2009) reflecting the impact of higher natural gas prices and changes in SCE's hedge portfolio mix; lower bilateral energy purchase expense of $50 million primarily due to decreased kWh purchases associated with overall lower kWh demand; and lower net ISO-related and other energy costs of $50 million primarily due to milder weather experienced during 2010 compared to 2009. These decreases were partially offset by the purchase of replacement power costs related to the San Onofre Unit 2 extended outage and higher QF and renewable purchased power expense of $85 million primarily due to higher natural gas prices.

- Higher fuel expense of $10 million related to a $25 million increase at the Mountainview power plant resulting from higher natural gas prices and a $10 million decrease at Four Corners resulting from a planned outage in 2010.

- Higher operation and maintenance expense of $71 million primarily due to an increase in spending for various public purpose programs.

2009 vs. 2008

Utility cost-recovery activities excludes the impact of the consolidation of the Big 4 projects in 2009 and 2008 for comparability purposes. In addition to the 2009 amounts noted above, the following amounts were excluded for 2008: $692 million for purchased power expense to reflect the elimination of sales between the VIEs and SCE; $813 million for fuel expense; and $90 million for operation and maintenance expense. Utility cost-recovery activities were primarily affected by:

- Lower purchased power expense of $1.4 billion primarily due to: lower bilateral energy and QF purchases of $1.6 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 CAISO's MRTU market; and a change in net realized losses due to settled natural gas prices being significantly lower than average fixed prices. Realized losses on economic hedging activities were $344 million in 2009 and $60 million in 2008.

- Lower fuel expense of $234 million primarily due to lower costs at the Mountainview plant resulting from lower natural gas costs in 2009 compared to 2008.

- Higher operation and maintenance expense of $105 million primarily related to the presentation of $185 million of medical, dental, and vision expenses and its share of Palo Verde operation and maintenance expenses which beginning in 2009 are reflected in cost-recovery activities consisting with the balancing account ratemaking treatment authorized in SCE's 2009 GRC. In addition, SCE recorded 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 and $85 million of lower transmission access and reliability service charges.

Supplemental Operating Revenue Information

SCE's retail billed and unbilled revenue (excluding wholesale sales and balancing account over/undercollections) was $10 billion, $9.5 billion and $9.3 billion for 2010, 2009 and 2008. The 2010 and 2009 increases reflect a rate increase of $777 million and $564 million, respectively, and a sales volume decrease

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of $255 million and $380 million, respectively. The 2010 rate increase was due to higher system average rates for 2010 compared to the same periods in 2009 mainly due to the implementation of the CPUC 2009 GRC decision and approved FERC transmission rate changes. The 2010 sales volume decrease was primarily due to milder weather experienced during 2010 compared to the same period in 2009. Economic conditions continued to contribute to the sales volume decrease. The 2009 rate increase reflects a rate change effective April 4, 2009 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 2009 sales volume decrease was due to the economic downturn as well as the milder weather experienced in 2009 compared to the same period in 2008. As a result of the CPUC-authorized decoupling mechanism, SCE does not bear the volumetric risk related to retail electricity sales (see "Item 1. Business Southern California Edison Company Overview of Ratemaking Mechanisms").

SCE remits to CDWR and does not recognize as revenue the amounts that 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. The amounts collected and remitted to CDWR were $1.2 billion, $1.8 billion and $2.2 billion for years ended December 31, 2010, 2009 and 2008, respectively. Effective January 1, 2010, the CDWR-related rates were decreased to reflect lower power procurement expenses and to refund operating reserves that CDWR can release as these contracts begin to terminate. The remaining power contracts that CDWR allocated to SCE will terminate by the end of 2011. SCE's revenue and related purchased power expense is expected to increase as these CDWR contracts are replaced by power purchase agreements entered into by SCE.

Income Taxes

The table below provides an analysis of the principal factors impacting SCE's effective tax rate.

	Years ended December 31,		
	2010	**2009**	**2008**
Income from continuing operations before income taxes	$ 1,532	$ 1,620	$ 1,246
Net income attributable to noncontrolling interest in the Big 4 projects		(94)	(170)
Adjusted income from continuing operations before income taxes	$ 1,532	$ 1,526	$ 1,076
Provision for income tax at federal statutory rate of 35%	$ 536	$ 534	$ 377
Increase (decrease) in income tax from:			
Items presented with related state income tax, net			
Global settlement related	(95)	(306)	
Change in tax accounting method for asset removal costs[1]	(40)		
State tax net of federal benefit	59	67	37
Health care legislation[2]	39		
Property-related and other	(59)	(46)	(72)
Total income tax expense from continuing operations	$ 440	$ 249	$ 342
Effective tax rate	28.7%	16.3%	31.8%

1 During the second quarter of 2010, the IRS approved SCE's request to change its tax accounting method for asset removal costs primarily related to its infrastructure replacement program. As a result, SCE recognized a $40 million earnings benefit ($28 million of which relates to asset removal costs incurred prior to 2010) from deducting asset removal costs earlier in the construction cycle. These deductions are recorded on a flow-through basis.

2 During the first quarter of 2010, SCE recognized a $39 million non-cash charge to reverse previously recognized federal tax benefits eliminated by the federal health care legislation enacted in March 2010. The Patient Protection and Affordable Care Act, as modified by the Health Care and Education Reconciliation Act, includes a provision that eliminates the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies. Although this change does not take effect until January 1, 2013, SCE is required to recognize the full accounting

impact of the legislation in its financial statements in the period of enactment.

LIQUIDITY AND CAPITAL RESOURCES

SCE's ability to operate its business, complete planned capital projects, and implement its business strategy are dependent upon its cash flow and access to the capital markets to finance its activities. SCE's overall cash flows fluctuate based on, among other things, its ability to recover its costs in a timely manner from its

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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 expects to fund its continuing obligations and projected capital expenditures for 2011 and dividends to Edison International through cash and equivalents on hand, operating cash flows, tax benefits and capital market financings of debt and preferred equity, as needed. SCE also has availability under its credit facilities if additional funding and liquidity are necessary to meet operating and capital requirements.

Available Liquidity

As of December 31, 2010, SCE had approximately $257 million of cash and equivalents. SCE had two credit facilities: 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 three-year credit facility that matures in March 2013.

(in millions)	**Credit Facilities**	
Commitment	$	2,894
Outstanding borrowings		
Outstanding letters of credit		(24)
Amount available	$	2,870

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, 2010, SCE's debt to total capitalization ratio was 0.46 to 1.

Capital Investment Plan

SCE's capital expenditures for 2011 2014 include a capital forecast in the range of $15.6 billion to $17.5 billion. The 2011 planned capital expenditures 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 the 2012 2014 planned capital expenditures for projects under CPUC jurisdiction and not already approved through other CPUC-authorized mechanisms, is subject to the outcome of the 2012 CPUC GRC or other CPUC approvals. The 2011 planned capital expenditures for projects under FERC jurisdiction are recovered through the authorized FERC revenue requirement. Recovery of the 2012 2014 planned capital expenditures under FERC jurisdiction will be requested in future FERC transmission filings, as applicable.

The completion of 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's capital expenditures (including accruals) in 2010 were $3.8 billion. The estimated capital expenditures for the next four years may vary from SCE's current forecast in a range of $15.6 billion to $17.5 billion based on the average variability experienced in 2009 and 2010 of 10.5%. SCE's 2010 capital expenditures and the 2011 2014 capital expenditures forecast, including the two-year historical average variability to the current forecast, is set forth in the table below:

(in millions)	2010 Actual	2011	2012	2013	2014	Total
Distribution	$ 1,875	$ 1,964	$ 2,336	$ 2,366	$ 2,440	$ 9,106
Transmission	712	1,127	1,556	1,268	1,006	4,957
Generation	643	657	550	579	543	2,329
EdisonSmartConnect™	413	400	266			666
Solar Rooftop Program	137	202	141	71		414
Total Estimated Capital Expenditures[1]	$ 3,780	$ 4,350	$ 4,849	$ 4,284	$ 3,989	$ 17,472
Total Estimated Capital Expenditures for 2011 2014 (using 10.5% variability discussed above)		$ 3,893	$ 4,340	$ 3,833	$ 3,571	$ 15,638

1 Included in SCE's capital expenditures plan are projected environmental capital expenditures of $397 million in 2011. The projected environmental capital expenditures are to comply with laws, regulations, and other nondiscretionary requirements.

Distribution Projects

Distribution expenditures include projects and programs to meet customer load growth requirements, reliability and infrastructure replacement needs, information and other technology and related facility requirements. Of the total forecasted distribution expenditures, $2.0 billion are recoverable 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 11-segment project consisting of new and upgraded transmission lines and associated substations primarily built to enhance reliability and enable the delivery of renewable energy generated primarily by wind farms in remote areas of eastern Kern County, California. Tehachapi segments 1, 2 and a portion of segment 3 were completed and placed in service in 2009. The remainder of segment 3 is under construction and expected to be placed in service over the period 2012 2013. SCE continues to seek the necessary licensing permits for Tehachapi segments 4 through 11, which are expected to be placed in service between 2011 and 2015, subject to receipt of licensing and regulatory approvals. SCE expects to invest $1.3 billion over the period 2011 2014 on this project. The FERC approved a 125 basis point ROE project adder, a 50 basis point incentive for CAISO participation, 100% CWIP in rate base treatment, and the ability to seek recovery of 100% abandoned plant costs (if any) on this project.

Devers-Colorado River Project a transmission project involving the installation of a high voltage (500 kV) transmission line from western Riverside County, 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 2011 2013, SCE expects to invest $655 million for this project. The FERC approved a 100 basis point ROE project adder, a 50 basis point adder for CAISO participation, 100% CWIP in rate base treatment and the ability to seek recovery of 100% abandoned plant costs (if any) on this project.

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 $483 million over the period 2011 2013 on this project. The FERC approved a 50 basis point incentive for CAISO participation, 100% CWIP in rate base treatment, and the ability to seek recovery of 100% abandoned plant costs (if any) on this project.

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Red Bluff Substation Project a substation project that consists of a new 500/220 kV substation that loops into the existing Devers-Palo Verde 500 kV transmission line near Desert Center in Riverside County, California. The project is currently expected to be placed in service in 2013, subject to final licensing and regulatory approvals. SCE expects to invest $225 million over the period 2011 2013 on this project. The FERC approved 100% CWIP in rate base treatment and the ability to seek recovery of 100% abandoned plant costs (if any) on this project.

Other capital investments consisting of $2.3 billion to maintain reliability and expand capability of its infrastructure over the period 2011 2014.

Generation Projects

Generation expenditures of $2.3 billion include:

Nuclear-related capital expenditures that are necessary to maintain safe and reliable plant operation, meet NRC and other regulatory requirements, and optimize plant performance and cost-effectiveness.

Hydro-related capital expenditures associated with required infrastructure and equipment replacement and ongoing efforts to renew FERC licenses. Infrastructure expenditures generally include projects such as dam improvements, flowline and substation refurbishments, and powerline replacements. Equipment replacement expenditures generally include projects for transformers, automation, switchgear, hydro turbine repowers, generator rewinds, and small generator replacements.

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. SCE anticipates completion of the deployment in 2012.

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 CPUC has authorized recovery of reasonable costs and allowed for a return on its investment. In February 2011, SCE filed an application with the CPUC to reduce the maximum utility owned solar projects from 250 MW to 125 MW and to allow SCE to purchase power from new solar projects up to 125 MW in a separate solicitation not subject to the same parameters as the original Program. SCE filed this application to permit greater competition and reduce overall solar program customer costs. SCE's capital expenditures for the period 2011 2014 reflect this reduction in procurement obligations and related estimated cost savings.

Regulatory Proceedings

Energy Efficiency Shareholder Mechanism

In December 2010, the CPUC issued a decision approving a $24 million final payment for 2006 2008 performance under the Energy Efficiency Mechanism and also modifying the mechanism. The modified mechanism will also be applied to the 2009 energy efficiency program year. SCE anticipates filing an application with the CPUC for incentives related to the 2009 program year performance, in the first half of 2011.

Based on the modified mechanism, SCE may recognize a 2009 program year payment of up to an estimated $27 million by December 2011; however, there is no assurance that SCE will receive any payment for that period. Additionally, the CPUC may further modify or eliminate this mechanism. See "Item 1. Business Southern California Edison Company Regulation Energy Efficiency Shareholder Risk/Reward Incentive Mechanism" for further information on the Energy Efficiency Mechanism for the 2009 program year and the potential 2010 2012 mechanism.

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Ratemaking Mechanism to Track Bonus Depreciation

The CPUC has proposed a resolution that establishes a memorandum account to track the base rate revenue requirement reduction, if any, associated with the Small Business Jobs Act of 2010 and the 2010 Tax Relief Act from the effective date of the resolution to the effective date of SCE's 2012 GRC decision. The CPUC will determine at a future date whether rates should be changed to reflect any benefits attributable to these Acts. The impact on the 2011 base rate revenue requirement is dependent upon, the ratemaking mechanism adopted, the final IRS regulations, the timing and amount of actual capital expenditures, working capital requirements and work order closings.

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, 2010, SCE's 13-month weighted-average common equity component of total capitalization was 51% resulting in the capacity to pay $497 million in additional dividends.

During 2010, SCE made a total of $300 million of dividend payments to its parent, Edison International, and in February 2011 declared a $115 million dividend to Edison International which is payable in March 2011. Future dividend amounts and timing of distributions are dependent upon several factors including the actual level of capital expenditures, operating cash flows and earnings.

Income Tax Matters

Repair Deductions

In 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 a $192 million cash benefit realized in the fourth quarter of 2009. This initial benefit was based 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. The deduction reflected on the 2009 income tax return was consistent with this cash benefit. The amount claimed on the 2009 tax return may be revised in the future based on further guidance from the IRS. The income tax benefit from the change in accounting for repair costs represents a timing difference which will reverse over the estimated remaining tax life of the assets. This method change, and incremental deductions taken in 2009 and 2010, did not impact SCE's 2009 or 2010 results of operations. Regulatory treatment for future increases in income taxes related to this matter will be addressed in SCE's 2012 GRC. SCE has not recognized an earnings benefit or regulatory asset, as the regulatory treatment is pending.

Margin and Collateral Deposits

Derivative Instruments and Power Procurement Contracts

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, 2010, 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 procurement 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

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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, 2010.

(in millions)

Collateral posted as of December 31, 2010[1]	$	33
Incremental collateral requirements for power procurement contracts resulting from a potential downgrade of SCE's credit rating to below investment grade		150
Posted and potential collateral requirements for derivative instruments and power procurement contracts[2]	$	183

1 Collateral posted consisted of $4 million which was offset against net derivative liabilities and $29 million provided to counterparties and other brokers (consisting of $5 million in cash reflected in "Other current assets" on the consolidated balance sheets and $24 million in letters of credit).

2 Total posted and potential collateral requirements may increase by an additional $19 million, based on SCE's forward positions as of December 31, 2010, due to adverse market price movements over the remaining life of the existing power procurement contracts using a 95% confidence level.

Potential Regulation of Swaps under the Dodd-Frank Act

The Dodd-Frank Act may impact margin, capital and collateral requirements in the future. See "Edison International (Consolidated) Liquidity and Capital Resources Potential Regulation of Swaps under the Dodd-Frank Act" for further discussion.

Workers Compensation Self-Insurance Fund

SCE is self-insured for workers compensation claims. SCE assesses workers compensation claims that have been asserted and those that have been incurred but not reported to determine the probable amount of losses that should be recorded. The Department of Industrial Relations for the State of California requires companies that are self-insured for workers compensation to post collateral (in the form of cash and/or letters of credits) based on the estimated workers' compensation liability if a company's bond rating were to fall below "B." As of December 31, 2010, if SCE's bond rating were to fall below a "B" rating, SCE would be required to post $209 million for its workers compensation self-insurance plan.

Regulatory Balancing Accounts

SCE's cash flows are affected by regulatory balancing account over or under collections. Balancing account over and under collections represent differences between cash collected in current rates and the costs incurred related to these regulatory mechanisms. In general, SCE seeks to adjust rates on an annual basis to recover or refund the balances recorded in certain balancing accounts. However, some over collections relate to specific programs that the CPUC has established annual funding levels in which funds must be spent by a certain date and therefore these over collections are not necessarily included in annual rate changes. Balancing account under collections and over collections accrue interest based on a three-month commercial paper rate published by the Federal Reserve.

As of December 31, 2010, balancing account net over collections were $1.3 billion primarily related to base rate differences, fuel and power procurement-related costs (ERRA) and various public purpose related-program costs. SCE expects to refund the base rate and ERRA combined over collection of $516 million through a rate adjustment beginning on June 1, 2011. The remaining over collections are expected to decrease as costs are incurred, amounts are refunded to ratepayers, or used to fund future programs established by the CPUC. Balancing account over or under collections may fluctuate due to, among other things, changes in: sales volume driven by growth or declines in customer base and weather; procurement-related costs driven both by market prices and sales volumes; and timing of expenditures under certain public purpose programs.

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Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for SCE:

Condensed Statement of Cash Flows

(in millions)	2010	2009	2008
Net cash provided by operating activities	$ 3,386	$ 4,069	$ 1,622
Net cash provided (used) by financing activities	503	(1,999)	2,024
Net cash used by investing activities	(4,094)	(3,219)	(2,287)
Net increase (decrease) in cash and cash equivalents	$ (205)	$ (1,149)	$ 1,359

Net Cash Provided by Operating Activities

Cash provided by operating activities decreased $683 million in 2010, compared to the same period in 2009. The cash flows provided by operating activities were primarily due to the following:

- $531 million decrease in cash reflecting lower net tax receipts in 2010 compared to 2009 primarily related to the impacts of the Global Settlement. In 2009, SCE received tax-allocation payments of $875 million from the Global Settlement, compared to tax-allocation payments received of $26 million in 2010. This decrease was partially offset by higher estimated tax payments in 2009 compared to 2010.

- $155 million net cash inflow from balancing accounts composed of:

  - $310 million net cash inflow from the funding of public purpose and solar initiative programs and lower pension and PBOP contributions in 2010 compared to 2009; and

  - $155 million net cash outflow due to the decrease in ERRA balancing account cash flows (collections of approximately $300 million in 2010, compared to collections of approximately $450 million in 2009). The ERRA balancing account was over-collected by $345 million at December 31, 2010, over-collected by $46 million at December 31, 2009 and under-collected by $406 million at December 31, 2008.

- Timing of cash receipts and disbursements related to working capital items, including a net cash outflow of $95 million related to the timing of fuel and power procurement-related activities primarily related to ISO charges and a $60 million decrease in margin and collateral deposits net of collateral received.

Cash provided by operating activities increased $2.4 billion in 2009, compared to the same period in 2008. The cash flows provided by operating activities were primarily due to the following:

- $875 million cash inflow from the receipt of 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.

- $468 million net cash inflow due to the increase in balancing account cash flows composed 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).

$820 million net cash outflow related 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.

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$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.

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.

Net Cash 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 provided by financing activities for 2010 was $503 million consisting of the following significant events:

Issued $1 billion of first refunding mortgage bonds due in 2040 to fund SCE's capital program.

Reissued $144 million of tax-exempt pollution control bonds due in 2035 to fund SCE's capital program.

Repaid $250 million of senior unsecured notes.

Paid $300 million in dividends to Edison International.

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

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.

Repaid a net $1.9 billion of short-term debt.

Repaid $150 million of first and refunding mortgage bonds.

Purchased $219 million of two issues of tax-exempt pollution control bonds and converted the issues to a variable rate structure. As discussed above, SCE reissued $144 million of these bonds in 2010. SCE continues to hold the remaining $75 million of these bonds which are outstanding and have not been retired or cancelled.

Paid $300 million in dividends to Edison International.

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 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.

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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).

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 $3.8 billion, $3.0 billion and $2.3 billion for 2010, 2009 and 2008, respectively, primarily related to transmission and distribution investments. Net purchases of nuclear decommissioning trust investments and other were $219 million, $199 million and $7 million for 2010, 2009 and 2008, respectively.

Contractual Obligations and Contingencies

Contractual Obligations

SCE's contractual obligations as of December 31, 2010, for the years 2011 through 2015 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]	$ 15,631	$ 408	$ 817	$ 2,070	$ 12,336
Power purchase agreements[2]:					
Renewable energy contracts	13,676	340	1,062	1,267	11,007
Qualifying facility contracts	3,723	429	822	809	1,663
Other power purchase agreements	6,354	548	1,364	1,105	3,337
Other operating lease obligations[3]	528	61	116	96	255
Purchase obligations[4]:					
Fuel supply contract payments	1,584	260	367	309	648
Other commitments	34	5	13	13	3
Employee benefit plans contributions[5]	840	156	449	235	
Total[6,7]	$ 42,370	$ 2,207	$ 5,010	$ 5,904	$ 29,249

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Debt and Credit Agreements." Amount includes interest payments totaling $8 billion over applicable period of the debt.

2 Some of the power purchase agreements entered into with independent power producers are treated as operating leases and capital leases. At December 31, 2010, minimum operating lease payments for power purchase agreements were $740 million in 2011, $717 million in 2012, $761 million in 2013, $708 million in 2014, $693 million in 2015, and $8.7 billion for the thereafter period. At December 31, 2010, minimum capital lease payments for power purchase agreements were $33 million in 2011, $71 million 2012, $131 million for 2013, $153 million for 2014, $154 million for 2015, and $2.5 billion for the thereafter period (amounts include executory costs and interest of $628 million and $1.2 billion, respectively). For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

3 At December 31, 2010, minimum other operating lease payments were primarily related to vehicles, office space and other equipment. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

4 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

5

Amount includes estimated contributions to the pension and PBOP plans. These amounts represent estimates that are based on assumptions that are subject to change. The estimated contributions for SCE are not available beyond 2014. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 8. Compensation and Benefit Plans" for further information.

6

At December 31, 2010, SCE had a total net liability recorded for uncertain tax positions of $335 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 6. Derivative Instruments and Hedging Activities," and "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment," respectively.

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Contingencies

SCE has contingencies related to FERC Rate Case, the Navajo Nation Litigation, nuclear insurance and spent nuclear fuel, which are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

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 timing of cash flows is uncertain.

As of December 31, 2010, SCE identified 23 sites for remediation and recorded an estimated minimum liability of $50 million. SCE expects to recover 90% of its remediation costs at certain sites. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. 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 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. SCE's authorized return on common equity was 11.5% for 2010, 2009 and 2008, respectively, and has been authorized to remain at 11.5% through December 2012 absent any future potential annual adjustment. SCE's authorized return on common equity is established in a multi-year cost of capital mechanism, which allows for annual adjustments if certain thresholds are reached. Variances in actual financing costs compared to authorized financing costs impact earnings either positively or negatively.

At December 31, 2010, the fair market value of SCE's long-term debt (including current portion of long-term debt) was $8.3 billion, compared to a carrying value of $7.6 billion. A 10% increase in market interest rates would have resulted in a $404 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 $444 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 reduces ratepayer exposure to variability in market prices related to SCE's power and gas activities. SCE expects recovery of 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 the timing of cash flows.

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. For further discussion on derivative instruments entered into to

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mitigate commodity price exposures, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Derivative Instruments and Hedging Activities."

Fair Value of Derivative 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 exception. 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. For further discussion on fair value measurements and the fair value hierarchy, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Fair Value Measurements."

The fair value of outstanding derivative instruments used at SCE to mitigate its exposure to commodity price risk was a net liability of $207 million and $251 million at December 31, 2010 and 2009, respectively. The following table summarizes the increase or decrease to the fair values of outstanding derivative instruments as of December 31, 2010, if the electricity prices or gas prices were changed while leaving all other assumptions constant:

(in millions)	**December 31, 2010**
Increase in electricity prices by 10%	$ 440
Decrease in electricity prices by 10%	(585)
Increase in gas prices by 10%	(302)
Decrease in gas prices by 10%	126

Credit Risk

For information related to credit risks and how SCE manages credit risk, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Derivative Instruments and Hedging Activities."

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 consolidated balance sheets. 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. SCE manages the credit risk on the portfolio for both rated and non-rated 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. As of December 31, 2010, the amount of balance sheet exposure as described above broken down by the credit ratings of SCE's counterparties, was as follows:

	December 31, 2010		
(in millions)	**Exposure[2]**	**Collateral**	**Net Exposure**
S&P Credit Rating[1]			
A or higher	$ 168	$	$ 168
A-	37		37
BBB+			
BBB			
BBB-			
Below investment grade			
Not rated	118	(34)	84
Total	$ 323	$ (34)	$ 289

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 purchases and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheets, except for any related net accounts receivable.

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The credit risk exposure set forth in the table above is composed of $7 million of net account receivables and $316 million representing the fair value, adjusted for counterparty credit reserves, of derivative contracts.

Four counterparties comprise 88% of the net exposure in the table above. The largest single net exposure was with the CAISO, mainly related to the CRRs' fair value, comprising 47% of the total net exposure in the table above.

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EDISON MISSION GROUP

RESULTS OF OPERATIONS

The following table is a summary of EMG's results of operations. Effective January 1, 2010, Edison International combined the competitive power generation and financial services segments into one business segment. The change resulted from termination of cross-border leases during 2009 and the continued reduction of the remaining portfolio of the financial services segment. Accordingly, the financial services segment has been combined retroactively for all periods presented into the competitive power generation business segment. The combination of these business activities is consistent with the management structure of EMG and evaluation of performance by Edison International.

Results of Continuing Operations

This section discusses operating results for 2010, 2009 and 2008. EMG's continuing operations 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. EMG's discontinued operations include all of its former international operations, except the Doga project.

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

	For The Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Competitive power generation operating revenue	$ 2,429	$ 2,399	$ 2,865
Fuel	809	796	747
Other operation and maintenance	1,020	964	1,013
Depreciation, decommissioning and amortization	249	239	198
Lease terminations and other	48	891	(35)
Total operating expenses	2,126	2,890	1,923
Operating income (loss)	303	(491)	942
Interest and dividend income	30	30	48
Equity in income from partnerships and unconsolidated subsidiaries net	106	89	119
Other income	8	12	12
Interest expense net of amounts capitalized	(264)	(306)	(288)
Other expenses		(9)	
Income (loss) from continuing operations before income taxes	183	(675)	833
Income tax expense (benefit)	(36)	(284)	272
Income (loss) from continuing operations	219	(391)	561
Income (loss) from discontinued operations net of tax	4	(7)	
Net income (loss)	223	(398)	561
Less: Net loss attributable to noncontrolling interests	(1)	(3)	

Net income (loss) available for common stock	$ 224	$ (395)	$ 561
Core Earnings[1]	$ 192	$ 222	$ 561
Non-Core Earnings (Loss):			
Global Settlement[2]	52	(610)	
Write-off of capitalized costs	(24)		
Discontinued Operations	4	(7)	
Total EMG GAAP Earnings (Loss)	$ 224	$ (395)	$ 561

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

2 Includes termination of Edison Capital's cross-border leases and state tax impact of Global Settlement with the IRS.

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EMG's 2010 core earnings were lower than 2009 core earnings primarily due to the following pre-tax items:

$108 million decreased income from Midwest Generation and Homer City primarily as a result of unrealized losses in 2010 compared to unrealized gains in 2009 related to hedge contracts, and higher plant maintenance costs in 2010, partially offset by higher capacity revenues and a $24 million gain on the sale of bankruptcy claims against Lehman Brothers. Energy and fuel related unrealized losses in 2010 were $33 million compared to unrealized gains of $60 million in 2009. Results in 2010 included the benefit of power hedge contracts entered into during earlier periods at higher prices than current energy prices. For additional information about market conditions, see "EMG: Market Risk Exposures."

$33 million gain in the second quarter of 2009 from the sale of an interest in a leverage lease (Midlands Cogeneration Ventures).

The decrease was offset by the following pre-tax items:

$61 million increased energy trading revenues due to congestion and power trading.

$34 million decreased interest expense, net of interest income, primarily due to the increase in the capitalization of interest on projects under construction.

$25 million decreased corporate expenses due primarily to lower renewable energy development expenses.

$13 million increased income from distributions received from the March Point and Doga projects.

In addition to the preceding pre-tax items, core earnings in 2010 were lower due to $15 million of increased tax expenses that resulted from the recapture of Section 199 deductions realized in prior years resulting from the carryback of net operating tax losses.

Consolidated non-core items for EMG included:

An earnings benefit of $52 million in 2010 related to the acceptance by the California Franchise Tax Board of the tax positions finalized with the IRS in 2009 as part of the Global Settlement and a revision to interest on federal disputed tax items.

An after-tax loss of $610 million recorded in 2009 ($920 million pre-tax) resulting from the Global Settlement with the IRS and termination of Edison Capital's cross-border leases.

An after-tax earnings charge of $24 million ($40 million pre-tax) recorded in the fourth quarter of 2010 resulting from the write-off of capitalized engineering and other costs for air emissions control technology that is not currently being pursued for use at the Powerton Station. These activities were previously suspended as Midwest Generation pursued testing and evaluation of the use of a dry sorbent injection system using Trona or similar sorbents, which is expected to require lower capital costs. The Illinois EPA recently issued a construction permit to authorize installation of a dry sorbent injection system, which Midwest Generation currently expects to use if this project is undertaken. For further discussion, see "Edison International Overview Environmental Developments Midwest Generation Environmental Compliance Plans and Costs."

Adjusted Operating Income (Loss) ("AOI") Overview

The following section and table provide a summary of results of EMG's operating projects and corporate expenses for the three years ended December 31, 2010, together with discussions of the contributions by specific projects and of other significant factors affecting these results.

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The following table shows the adjusted operating income of EMG's projects:

(in millions)	Years ended December 31, 2010	2009	2008
Midwest Generation plants	$ 264	$ 340	$ 688
Homer City plant	114	186	202
Renewable energy projects	51	53	60
Energy trading	110	49	164
Big 4 projects	52	46	87
Sunrise	33	37	24
Doga	15	8	8
March Point[1]	17	11	
Westside projects	1	4	9
Leveraged lease income	5	14	51
Lease terminations and other	(3)	(887)	49
Other projects	10	3	9
Other operating income (expense)	1	(2)	(31)
	670	(138)	1,320
Corporate administrative and general	(150)	(175)	(182)
Corporate depreciation and amortization	(19)	(15)	(12)
AOI[2]	$ 501	$ (328)	$ 1,126

1 Sold in 2010.

2 AOI is equal to operating income (loss) under GAAP, plus equity in income 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 EMG.

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

(in millions)	Years ended December 31, 2010	2009	2008
AOI	$ 501	$ (328)	$ 1,126
Less:			
Equity in income of unconsolidated affiliates	106	89	119
Dividend income from projects	21	12	10
Production tax credits	62	56	44
Other income, net	8	3	11
Net loss attributable to noncontrolling interests	1	3	
Operating Income (Loss)	$ 303	$ (491)	$ 942

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Adjusted Operating Income from Consolidated Operations

Midwest Generation Plants

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

	Years ended December 31		
(in millions)	**2010**	**2009**	**2008**
Operating Revenues	$ 1,479	$ 1,487	$ 1,778
Operating Expenses			
Fuel[1]	519	547	482
Plant operations	448	396	431
Plant operating leases	75	75	75
Depreciation and amortization	114	109	106
Asset write-downs and (gain) on buyout of contract	42	2	(16)
Administrative and general	22	21	22
Total operating expenses	1,220	1,150	1,100
Operating Income	259	337	678
Other Income	5	3	10
AOI	$ 264	$ 340	$ 688
Statistics			
Generation (in GWh)			
Energy contracts	29,798	28,977	26,010
Load requirements services contracts		1,333	5,090
Total	29,798	30,310	31,100

1 Included in fuel costs were $13 million, $63 million and $5 million in 2010, 2009 and 2008, respectively, related to the net cost of emission allowances. Transfers of emission allowances between Midwest Generation and Homer City are made at fair market value. Transfers of NO_X emission allowances to Midwest Generation were $0.4 million and $1 million in 2010 and 2009, respectively. There were no NO_x transfers in 2008. Transfers of SO_2 emission allowances from Midwest Generation were $5 million and $2 million in 2010 and 2008, respectively. There were no SO_2 transfers 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 Midwest Generation plants decreased $76 million in 2010 compared to 2009, and decreased $348 million in 2009 compared to 2008. Excluding the $40 million pre-tax charge related to the Powerton Station, the 2010 decrease in AOI was primarily attributable to unrealized losses in 2010 compared to unrealized gains in 2009 related to hedge contracts and an increase in plant maintenance costs, partially offset by higher capacity revenues, a gain from the sale of the bankruptcy claims against Lehman Brothers, and lower average realized fuel costs. Plant maintenance and overhaul related expenses were higher in 2010 due to the deferral of plant outages in 2009. Average realized fuel costs per megawatt-hour were lower in 2010 as compared to 2009 primarily due to lower emission allowance costs partially offset by higher costs for activated carbon, which is used to reduce mercury emissions.

The 2009 decrease in AOI as compared to 2008 was primarily attributable to lower realized energy prices and higher average realized fuel costs, partially offset by higher capacity revenues, unrealized gains in 2009 compared to unrealized losses in 2008 related to hedge contracts, and lower plant operations expense. The 2009 increase in average realized fuel costs was due to higher emission allowance costs to comply with the CAIR annual NO_x emission program that began in 2009 and higher costs for activated carbon to implement new mercury emission controls. The 2009 decline in plant operations expense was due to cost containment efforts and the deferral of plant overhaul activities.

Included in operating revenues were unrealized gains (losses) of $(6) million, $30 million and $(6) million in 2010, 2009 and 2008, respectively. Unrealized gains (losses) in 2010 and 2009 were primarily due to economic hedge contracts that are accounted for at fair value with offsetting changes recorded on the consolidated statements of income. In addition, $10 million and $14 million were reversed from accumulated other comprehensive income and recognized in 2010 and 2009, respectively, related to the power contracts with Lehman Brothers. Unrealized losses in 2008 included a $24 million write-down of power contracts with Lehman Brothers for 2009 and 2010 forecasted generation. These contracts qualified as cash flow hedges until EMG 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 the Northern Illinois Hub (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.

Included in fuel costs were unrealized gains (losses) of $(7) million and $15 million for the year ended December 31, 2010 and 2009, respectively, due to oil futures contracts that were accounted for as economic hedges. These contracts were entered into in 2010 and 2009 to hedge variable fuel oil components of rail transportation costs.

Homer City

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

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Operating Revenues	$ 636	$ 663	$ 717
Operating Expenses			
Fuel[1]	279	251	270
Plant operations	117	104	126
Plant operating leases	103	102	102
Depreciation and amortization	18	16	16
Administrative and general	5	4	4
Total operating expenses	522	477	518
Operating Income	114	186	199
Other Income			3
AOI	$ 114	$ 186	$ 202
Statistics			
Generation (in GWh)	11,028	11,446	11,334

1 Included in fuel costs were $7 million, $16 million and $20 million in 2010, 2009 and 2008, respectively, related to the net cost of emission allowances. Transfers of emission allowances between Midwest Generation and Homer City are made at fair market value. Transfers of SO_2 emission allowances to Homer City were $5 million and $2 million in 2010 and 2008, respectively. There were no SO_2 transfers in 2009. Transfers of NO_x emission allowances from Homer City were $0.4 million and $1 million in 2010 and 2009, respectively. There were no NO_x transfers in 2008. For more information regarding the price of emission allowances, see "EMG: Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk."

On February 10, 2011, a steam pipe ruptured at Unit 1 of the Homer City plant, taking the unit off line. As a precautionary measure, Homer City has taken Unit 2 (which has the same design) off line in order to further evaluate the equipment and perform any necessary corrective work. Work has commenced to inspect the piping that failed and planning activities to install replacement piping on both units are underway. Homer City is in the process of modifying its scheduled maintenance plans to incorporate this outage. It is expected that both units will return to service during the second quarter of 2011.

AOI from the Homer City plant decreased $72 million in 2010 compared to 2009 and decreased $16 million in 2009 compared to 2008. The 2010 decrease in AOI was primarily attributable to unrealized losses in 2010 compared to unrealized gains in 2009 related to hedge contracts, higher coal costs, lower generation, and higher plant operations costs related to scheduled plant outages, partially offset by an increase in capacity revenues. The Homer City plant experienced increased forced outages in 2010 compared to 2009 due to deratings to comply with opacity restrictions and unscheduled outages. Plant maintenance and overhaul related expenses were higher in 2010 due to the deferral of plant outages in 2009. Coal costs increased due to higher coal prices and changes in the mix of ready-to-burn coal and raw coal consumed.

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The 2009 decrease in AOI as compared to 2008 was primarily attributable to lower realized energy prices, partially offset by an increase in capacity revenues, lower plant operations expense and lower coal costs. The decline in plant operations expense was attributable to cost containment efforts and the deferral of plant overhaul activities.

Included in operating revenues were unrealized gains (losses) from hedge activities of $(20) million, $15 million and $21 million in 2010, 2009 and 2008, 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 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 plant is delivered into the transmission system).

Renewable Energy Projects

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

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Operating Revenues	$ 137	$ 141	$ 108
Production Tax Credits	62	56	44
	199	197	152
Operating Expenses			
Plant operations	55	55	35
Depreciation and amortization	89	92	59
Asset impairment and sale of assets	3		
Administrative and general	3	3	2
Total operating expenses	150	150	96
Other Income	2	3	4
Net Loss Attributable to Noncontrolling Interests		3	
AOI[1]	$ 51	$ 53	$ 60
Statistics			
Generation (in GWh)[2]	3,646	3,081	2,286

1 AOI is equal to operating income (loss) plus equity in income (losses) of unconsolidated affiliates, 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.

2 Includes renewable energy projects that are unconsolidated at EMG. Generation excluding unconsolidated projects was 3,037 GWh in 2010 and 2,514 GWh in 2009.

AOI from renewable energy projects decreased $2 million in 2010 compared to 2009, and decreased $7 million in 2009 compared to 2008. The 2010 decrease was primarily due to the impairment of a Minnesota Wind project and an increase in costs related to projects under construction. 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. EMG's share of installed capacity of new wind projects that commenced operations during 2010, 2009 and 2008 was 150 MW, 223 MW and 396 MW, respectively.

AOI in 2010, 2009 and 2008 included payments from Suzlon Wind Energy Corporation for availability losses of $2 million, $17 million and $28 million, respectively. Payments under the availability guarantee are designed to compensate EMG for lost earnings, including production tax credits. Accordingly, the payments under the availability guarantee are paid on a pre-tax basis which affects period-to-period comparisons that include production tax credits which are after tax.

Energy Trading

EMG seeks to generate profit by utilizing its subsidiary, EMMT, to engage in trading activities primarily 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, coal, 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 increased $61 million in 2010 compared to 2009, and decreased $115 million in 2009 compared to 2008. The 2010 increase in AOI energy trading activities was attributable to increased revenues in congestion and power trading. Congestion trading results increased in 2010 compared to 2009 due to unseasonable cold weather and transmission outages in the New York and PJM markets. The 2009 decrease in AOI from energy trading activities was attributable to lower transmission congestion in the eastern U.S. power grid. In addition, energy trading included favorable results for load service transactions in 2009.

Adjusted Operating Income from Leveraged Lease Activities and Lease Terminations and Other

AOI from leveraged lease income in 2009 included a $920 million loss on termination of the cross-border leases, partially offset by a $33 million gain on the sale of an interest in a leveraged lease (Midlands Cogeneration Ventures). Leveraged lease income declined in 2010 and 2009 from 2008 primarily due to termination of the cross-border leases.

Other Operating Income (Expense)

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 development projects. These amounts are reflected in "Lease terminations and other" on the consolidated statements of income.

Corporate Administrative and General Expenses

Corporate administrative and general expenses decreased $25 million in 2010 from 2009 and decreased $7 million in 2009 from 2008. The 2010 and 2009 decreases were primarily attributable to lower development costs related to renewable energy. In April 2009, EMG reduced approximately 75 positions in its regional and corporate offices.

Interest Income (Expense)

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Interest income	$ 9	$ 17	$ 37
Interest expense, net of capitalized interest			
EME debt	(229)	(267)	(254)
Non-recourse debt	(35)	(39)	(34)
	$ (264)	$ (306)	$ (288)

Interest income decreased primarily due to lower interest rates and, to a lesser extent, lower average cash balances.

EMG's interest expense decreased $42 million in 2010 from 2009 and increased $18 million in 2009 from 2008. The 2010 decrease in interest expense was primarily due to higher capitalized interest and lower debt balances under EME's and Midwest Generation's credit facilities, partially offset by higher wind project financing. 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. Capitalized interest was $54 million,

$19 million and $32 million in 2010, 2009 and 2008, respectively. The 2010 increase was the result of increased interest capitalization for projects under construction. The change in capitalized interest during these periods relates to the increase or decrease in renewable projects under construction.

Income Taxes

The table below provides an analysis of the principal factors impacting EMG's effective tax rate:

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Income (loss) from continuing operations before income taxes	$ 183	$ (675)	$ 833
Provision for income tax expense (benefit) at federal statutory rate of 35%	$ 64	$ (236)	$ 292
Increase (decrease) in income tax from:			
Items presented with related state income tax, net			
Global settlement related	(52)	37	
State tax net of federal benefit	3	(20)	53
Production and housing credits	(66)	(63)	(56)
Property-related and other	15	(2)	(17)
Total income tax expense (benefit) from continuing operations	$ (36)	$ (284)	$ 272
Effective tax rate	(19.7)%	42.1%	32.7%

EMG's effective tax rate for 2010 was impacted by the Global Settlement and the recapture of qualified production deductions realized in prior years resulting from a carryback of net operating losses to 2008. 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. Estimated state income tax benefits allocated from Edison International of $7 million, $15 million and $5 million were recognized for the years ended December 31, 2010, 2009 and 2008, respectively.

For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 7. Income Taxes."

Results of Discontinued Operations

The 2010 results of discontinued operations included foreign exchange gains and interest expense on contract indemnities denominated in euros, adjustments to unrecognized tax benefits, and expiration in 2010 of another contract indemnity. The contract indemnities relate to the 2004 sale of EMG's international projects in December 2004. Results in 2009 and 2008 included foreign exchange gains (losses), change in estimates, and interest expense also associated with these contract indemnities.

Related-Party Transactions

EMG owns interests in partnerships that sell 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 $367 million, $366 million and $686 million in 2010, 2009 and 2008, respectively.

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LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

The following table summarizes available liquidity at December 31, 2010:

(in millions)	Cash and Cash Equivalents	Available Under Credit Facilities	Total Available Liquidity
EME as a holding company	$ 427	$ 484	$ 911
EME subsidiaries without contractual dividend restrictions	188		188
EME corporate cash and cash equivalents	615	484	1,099
EME subsidiaries with contractual dividend restrictions			
Midwest Generation[1]	295	497	792
Homer City	132		132
Other EME subsidiaries	33		33
Other EMG subsidiaries	24		24
Total	$ 1,099	$ 981	$ 2,080

1 Cash and cash equivalents are available to meet Midwest Generation's operating and capital expenditure requirements.

Because EME, as a holding company, does not directly own any revenue-producing generation facilities, EME relies on cash distributions and tax payments from its projects to meet its obligations, including debt service obligations on long-term debt. The timing and amount of distributions from EME's subsidiaries may be restricted. For further details, see " Debt Covenants and Dividend Restrictions Dividend Restrictions in Major Financings."

The following table summarizes the status of the EME and Midwest Generation credit facilities at December 31, 2010, which mature in June 2012:

(in millions)	EME	Midwest Generation
Commitments	$ 564	$ 500
Outstanding borrowings		
Outstanding letters of credit	(80)	(3)
Amount available	$ 484	$ 497

EME and Midwest Generation may seek to extend or replace credit facilities or retire them by other means. The terms and conditions of any refinancing could be substantially different than those in the current credit facilities. Senior notes in the principal amount of $500 million, which were issued in 2006 and which bear interest at 7.50% per annum, are due in June 2013. EME may also from time to time seek to retire or purchase its outstanding debt through cash purchases and/or exchange offers, open market purchases, privately negotiated transactions or otherwise, depending on prevailing market conditions, EME's liquidity requirements, contractual restrictions and other factors.

Midwest Generation has not yet committed to the completion of environmental compliance activities for all of its plants. Expenditures for NO_x and SO_2 controls through 2013 are estimated at $481 million based on an assumption that Midwest Generation would retrofit all units over the compliance period, which extends to 2018. Depending upon the facilities selected to be retrofitted, the cost of such retrofitting, and the timing of funding requirements beyond the near term, Midwest Generation may utilize operating cash flow, draw on its credit facilities, when available, or seek debt financing to fund capital expenditures.

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Capital expenditures to complete renewable energy projects through 2011 are projected to be $279 million at December 31, 2010. EMG anticipates that capital investment for renewable energy projects under or pending construction will be funded using a combination of construction and term financings, U.S. Treasury grants and third-party capital. EMG has available secured project financing of $48 million. In addition, U.S. Treasury grants of $346 million are anticipated based on estimated eligible construction costs for renewable projects completed in 2010 and scheduled to be completed in 2011.

Edison International's utilization of net operating losses and production tax credits from EMG in its consolidated return impacts EMG's liquidity. The bonus depreciation extension enacted in the Small Business Jobs Act of 2010 and the 2010 Tax Relief Act is expected to result in delays in EMG's receipt of future tax-allocation payments. For more information, see "EMG: Liquidity and Capital Resources Intercompany Tax-Allocation Agreement," "Edison International Overview Bonus Depreciation Impact on Edison International" and "Item 1A. Risk Factors Risks Relating to EMG Liquidity Risks."

Capital Investment Plan

At December 31, 2010, forecasted capital expenditures through 2013 by EMG's subsidiaries for existing projects, corporate activities and turbine commitments were as follows:

(in millions)	2011	2012	2013
Midwest Generation Plants			
Plant capital expenditures	$ 34	$ 23	$ 29
Environmental expenditures	151	132	198
Homer City Plant			
Plant capital expenditures	18	25	16
Environmental expenditures			
Renewable Energy Projects			
Capital and construction expenditures	189		
Turbine commitments	90		
Other capital expenditures	21	19	17
Total	$ 503	$ 199	$ 260

Environmental Capital Expenditures

Midwest Generation plants' environmental expenditures include $109 million for expenditures in 2011 related to SNCR equipment and $372 million for expenditures in 2011 to 2013 to begin to retrofit initial units using dry scrubbing with sodium-based sorbents to comply with CPS requirements for SO_2 emissions. Midwest Generation could elect to shut down units instead of installing controls to be in compliance with the CPS, and, therefore, decisions about any particular combination of retrofits and shutdowns it may ultimately employ to comply remain subject to conditions applicable at the time decisions are required or made. Accordingly, the environmental expenditures for Midwest Generation in the preceding table represent current projects only and are subject to change based upon a number of considerations. Actual expenditures could be higher or lower. Preconstruction engineering and initial construction work may occur in 2011 in advance of a final decision to continue or complete the project. For additional discussion, see "Edison International Overview Environmental Developments Midwest Generation Compliance Plans and Costs."

The capital investment plan set forth in the previous table does not include environmental capital expenditures for Homer City. However, depending on upcoming and future regulatory developments, Homer City may be required to undertake capital projects to install additional pollution control equipment which will be dependent on lessor decisions regarding the funding of these expenditures. For a discussion of environmental regulations, see "Edison International Overview Environmental Developments Homer City Environmental Issues and Capital Resource Limitations."

Non-Environmental Capital Expenditures

Plant capital expenditures in the preceding table relate to non-environmental projects such as upgrades to boiler and turbine controls, replacement of major boiler components, generator stator rewinds, condenser re-tubing, development of a coal-cleaning plant refuse site and a new ash disposal site, and main power transformer replacement.

Renewable energy projects' capital and construction expenditures include a project of an unconsolidated entity in which construction expenditures will be substantially funded by EMG. Construction project financing of $48 million was available as of December 31, 2010. In addition, U.S. Treasury grants of $346 million are anticipated based on estimated eligible construction costs for renewable projects completed in 2010 and scheduled to be completed in 2011.

Future Projects

At December 31, 2010, EMG had a development pipeline of potential wind projects with projected installed capacity of approximately 3,600 MW. The development pipeline represents potential projects with respect to which EMG either owns the project rights or has exclusive acquisition rights. Future development of the wind portfolio is dependent on the availability of third-party capital. To the extent that third-party capital is available, the success of development efforts will depend upon, among other things, obtaining permits and agreements necessary to support an investment. This process 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.

For additional information regarding capital expenditures for turbines and the Walnut Creek project, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies Other Commitments."

Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for EMG.

Condensed Statement of Cash Flows

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Operating cash flow from continuing operations	$ 306	$ (985)	$ 641
Operating cash flow from discontinued operations	4	(7)	
Net cash provided (used) by operating activities	310	(992)	641
Net cash provided (used) by financing activities	336	(656)	845
Net cash provided (used) by investing activities	(732)	861	(663)
Net increase (decrease) in cash and cash equivalents	$ (86)	$ (787)	$ 823

Net Cash Provided (Used) by Operating Activities

Cash provided by operating activities from continuing operations increased $1.3 billion in 2010, compared to the same period in 2009 primarily due to the impacts of the Global Settlement. In April 2010, Edison Capital funded a $253 million deposit to the IRS related to the Global Settlement. In 2009, Edison Capital made a net tax-allocation payment to Edison International of $1.1 billion related to the termination of Edison Capital's interest in cross-border leases (see "Item 8. Edison International Notes to Consolidated Financial Statements Note 7. Income Taxes" for further discussion). The 2010 increase was also due to higher realized revenue from derivative contracts and payments on U.S. Treasury grants.

Cash provided by operating activities from continuing operations decreased $1.6 billion in 2009 compared to 2008 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.

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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.

Net Cash Provided (Used) by Financing Activities

Cash provided by financing activities from continuing operations increased $1 billion in 2010, compared to the same period in 2009. In 2010, financing activities included project-level financing of renewable energy projects and repayment of credit facilities in 2009. In addition, in January 2010, Edison Capital redeemed in full its $89 million medium-term loans.

The 2009 increase as compared to 2008 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.

Net Cash Used by Investing Activities

Cash used by investing activities from continuing operations decreased $1.6 billion in 2010, compared to the same period in 2009. The 2010 decrease was primarily due to $1.385 billion of net proceeds from termination of the cross-border leases at Edison Capital in 2009. The change was also due to the construction of wind projects.

Credit Ratings

Overview

Credit ratings for EME, Midwest Generation and EMMT as of December 31, 2010 were as follows:

	Moody's Rating	S&P Rating	Fitch Rating
EME[1]	B3	B-	B-
Midwest Generation[2]	Ba2	B+	BB
EMMT	Not Rated	B-	Not Rated

1 Senior unsecured rating.

2 First priority senior secured rating.

All the above ratings are on negative outlook. EMG cannot provide assurance that its current credit ratings or the credit ratings of its subsidiaries will remain in effect for any given period of time or that one or more of these ratings will not be lowered. EMG notes that these credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

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

Credit Rating of EMMT

The Homer City sale-leaseback documents restrict Homer City's ability to enter into derivative activities with EMMT to sell forward the output of the Homer City plant 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 EMG'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. EMG currently sells all the output from the Homer City plant 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 plant through

EMMT, EMG 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 a requirement for EMMT to prepay for Homer City's output to satisfy a requirement under the terms of the consent that outstanding accounts receivable between EMMT and Homer City be reduced to zero. 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. EMG is permitted to sell the output of the Homer City plant into the spot market on the terms set forth in the Homer City sale-leaseback documents.

Margin, Collateral Deposits and Other Credit Support for Energy Contracts

To reduce its exposure to market risk, EMG 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. EMG has entered into guarantees in support of EMMT's hedging and trading activities; however, EMG 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, 2010, EMMT had deposited $43 million in cash with clearing brokers in support of futures contracts and had deposited $16 million in cash with counterparties in support of forward energy and congestion contracts. Cash collateral provided to others offset against derivative liabilities totaled $4 million at December 31, 2010. In addition, EMG had received cash collateral of $52 million at December 31, 2010 to support credit risk of counterparties under margin agreements. 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, 2010, if wholesale energy prices change or if EMMT enters into additional transactions. EMG estimates that margin and collateral requirements for energy and congestion contracts outstanding as of December 31, 2010 could increase by approximately $89 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 EMG 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."

Potential Regulation of Swaps under the Dodd-Frank Act

The Dodd-Frank Act may impact margin, capital and collateral requirements in the future. See "Edison International (Consolidated) Liquidity and Capital Resources Potential Regulation of Swaps under the Dodd-Frank Act" for further discussion.

Intercompany Tax-Allocation Agreement

EMG and its subsidiaries, 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. EMG made net tax-allocation payments of $371 million, $1.1 billion and $113 million in 2010,

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2009 and 2008, respectively. See "Edison International Overview Highlights of Operating Results" for information regarding the Global Settlement.

EME expects to receive tax-allocation payments in 2011 as a result of the carryback of Edison International consolidated net operating losses for 2010 and subsequently make tax-allocation payments in 2012 a result of reallocation of tax obligations from an expected Edison International consolidated net operating loss during 2011. For further information, see "Edison International Overview Bonus Depreciation Impact on Edison International."

Debt Covenants and Dividend Restrictions

Credit Facility Financial Ratios

EMG's credit facility contains financial covenants which require EMG to maintain a minimum interest coverage ratio and a maximum corporate-debt-to-capital ratio as such terms are defined in the credit facility. The following table sets forth the interest coverage ratio:

	Years ended December 31,	
(in millions)	**2010**	**2009**
Ratio	2.07	1.72
Covenant threshold (not less than)	1.20	1.20

The following table sets forth the corporate-debt-to-capital ratio:

	December 31,	
(in millions)	**2010**	**2009**
Corporate-debt-to-capital ratio	0.52	0.54
Covenant threshold (not more than)	0.75	0.75

Dividend Restrictions in Major Financings

Each of EMG's direct or indirect subsidiaries is organized as a legal entity separate and apart from EMG and its other subsidiaries. Assets of EMG's subsidiaries are not available to satisfy EMG'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 EMG or to its subsidiary holding companies.

Key Ratios of EMG's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EMG's principal subsidiaries required by financing arrangements at December 31, 2010 or for the 12 months ended December 31, 2010:

Subsidiary	**Financial Ratio**	**Covenant**	**Actual**
Midwest Generation (Midwest Generation plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.15 to 1
Homer City (Homer City plant)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.51 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

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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 Sale-Leaseback Restrictions on Distributions

Homer City completed a sale-leaseback of the Homer City plant 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 equity and debt portions of rent then due and payable must have been paid and the senior rent service coverage ratio for the prior 12-month period (taken as a whole and projected for each of the prospective two 12-month periods) must be greater than 1.7 to 1.

EMG's Senior Notes and Guaranty of Powerton-Joliet Leases

EMG is restricted under applicable agreements from selling or disposing of assets, which includes distributions, 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 the sale or disposition in question. At December 31, 2010, the maximum permissible sale or disposition of EMG assets was $872 million.

Contractual Obligations, Commercial Commitments and Contingencies

Contractual Obligations

EMG has contractual obligations and other commercial commitments that represent prospective cash requirements. The following table summarizes EMG's significant consolidated contractual obligations as of December 31, 2010.

(in millions)	Total	Payments Due by Period Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt[1]	$ 6,711	$ 340	$ 1,180	$ 842	$ 4,349
Power plant and other operating lease obligations[2]	3,166	339	664	496	1,667
Purchase obligations[3]:					
Fuel supply contracts	765	482	283		
Coal transportation agreements	231	231			
Gas transportation agreements	60	8	16	17	19
Capital expenditures	182	182			
Turbine commitments	90	90			
Other contractual obligations	198	85	103	8	2
Employee benefit plan contribution[4]	22	22			
Total Contractual Obligations[5,6]	$ 11,425	$ 1,779	$ 2,246	$ 1,363	$ 6,037

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Debt and Credit Agreements." Amount also includes interest payments totaling $2.3 billion over the applicable period of the debt.

2 At December 31, 2010, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet Stations and the Homer City plant. For further discussion, see " Off-Balance Sheet Transactions Sale-Leaseback Transactions" and "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

3 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

4 Amount includes estimated contribution for pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2011 are not available. For more information, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 8. Compensation and Benefit Plans Pension Plans and Postretirement Benefits Other than Pensions."

5 At December 31, 2010, EMG had a total net liability recorded for uncertain tax positions of $227 million, which is excluded from the table. EMG 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 7. 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 6. Derivative Instruments and Hedging Activities," and " Note 2. Property, Plant and Equipment," respectively.

Commercial Commitments

Standby Letters of Credit

As of December 31, 2010, standby letters of credit under EMG and its subsidiaries' credit facilities aggregated $116 million and were scheduled to expire as follows: $95 million in 2011, $11 million in 2012, and $10 million in 2017. Certain letters of credit are subject to automatic annual renewal provisions.

Contingencies

EMG's significant contingencies related to the Midwest Generation New Source Review lawsuit and Homer City New Source Review Lawsuit are discussed in "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. 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.

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Investments Accounted for under the Equity Method

EMG has a number of investments in power projects that are accounted for under the equity method. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 3. Variable Interest Entities."

Subsidiaries of EMG have invested in affordable housing projects utilizing partnership or limited liability companies in which EMG is a passive investor. With a few exceptions, an unrelated general partner or managing member exercises operating control of these projects and partnerships. The debt of those partnerships and limited liability companies is secured by real property. At December 31, 2010, entities that EMG has accounted for under the equity method had indebtedness of approximately $1.3 billion, of which approximately $451 million is proportionate to EMG's ownership interest in these projects. Substantially all of this debt is nonrecourse to EMG.

Sale-Leaseback Transactions

EMG 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 plant in Pennsylvania. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies Power Plant and Other Lease Commitments."

EMG's subsidiaries record depreciation expense from the power plants and interest expense from the lease financing in lieu of an operating lease expense which EMG uses in preparing its consolidated financial statements. The treatment of these leases as operating leases on its consolidated financial statements in lieu of lease financings, which are recorded by EMG's subsidiaries, resulted in an increase in consolidated net income of $36 million, $35 million and $46 million in 2010, 2009 and 2008, respectively.

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

Power Station(s)	Acquisition Price (in millions)	Equity Investor	Original Equity Investment in Owner-Lessor (in millions)	Amount of Lessor Debt at December 31, 2010 (in millions)		Maturity Date of Lessor Debt
Powerton/Joliet	$ 1,367	PSEG/Citigroup, Inc.	$ 238	$ 513	Series B	2016
Homer City	$ 1,591	GECC/Metropolitan Life Insurance Company	$ 798	$ 201	Series A	2019
				$ 495	Series B	2026

PSEG PSEG Resources, Inc.
GECC General Electric Capital Corporation

The operating lease payments to be made by each of EMG's subsidiary lessees are structured to service the lessor debt and provide a return to the owner-lessor's equity investors. Neither the value of the leased assets nor the lessor debt is reflected on EMG's consolidated balance sheet.

Leveraged Leases

Subsidiaries of EMG are lessors in power and infrastructure projects with terms of 25 to 30 years. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 15. Other Investments" for details of the lease investments.

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MARKET RISK EXPOSURES

Introduction

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

Derivative Instruments

EMG uses derivative instruments to reduce its exposure to market risks that arise from price fluctuations 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.

Unrealized Gains and Losses

EMG classifies unrealized gains and losses from derivative instruments (other than the effective portion of derivatives that qualify for hedge accounting) as part of operating revenues or fuel costs. 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:

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Midwest Generation plants			
Non-qualifying hedges	$ (11)	$ 40	$ (16)
Ineffective portion of cash flow hedges	(2)	5	10
Homer City plant			
Non-qualifying hedges	(1)	1	1
Ineffective portion of cash flow hedges	(19)	14	20
Total unrealized gains (losses)	$ (33)	$ 60	$ 15

At December 31, 2010, cumulative unrealized gains of $4 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to 2011.

Fair Value Disclosures

In determining the fair value of EMG's derivative positions, EMG uses third-party market pricing where available. For further explanation of the fair value hierarchy and a discussion of EMG's derivative instruments, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 4. Fair Value Measurements" and " Note 6. Derivative Instruments and Hedging Activities," respectively.

The fair value of derivatives used for non-trading purposes at December 31, 2010 was $46 million. A 10% change in the market price of the underlying commodity at December 31, 2010 would increase or decrease the fair value of outstanding non-trading commodity derivative instruments by approximately $58 million.

The fair value of derivatives used for trading purposes at December 31, 2010 was $110 million. A 10% change in the market price of the underlying commodity at December 31, 2010 would increase or decrease the fair value of trading contracts by approximately $26 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 EMG's results of operations as such changes would be offset by similar changes in derivatives classified within Level 3 as well as other levels. Level 3 assets and liabilities are 58% and 34%, respectively, of assets

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and liabilities measured at fair value before the impact of offsetting collateral and netting as of December 31, 2010.

Commodity Price Risk

Introduction

EMG'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 EMG's risk management policies. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

Energy Price Risk Affecting Sales from the Coal Plants

Energy and capacity from the coal plants 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, and to a lesser extent, the AEP/Dayton Hub, both in PJM, for the Midwest Generation plants and generally at the PJM West Hub for the Homer City plant.

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]		
	2010	2009	2008
Midwest Generation plants			
Northern Illinois Hub	$ 33.08	$ 28.86	$ 49.01
Homer City plant			
PJM West Hub	$ 45.88	$ 38.31	$ 68.56
Homer City Busbar	39.35	34.91	57.72

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, 2010:

	24-Hour Forward Energy Prices[1]	
	Northern Illinois Hub	PJM West Hub
2011 calendar "strip"[2]	$ 30.68	$ 45.45
2012 calendar "strip"[2]	$ 32.37	$ 46.41

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 points.

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 coal plants into these markets may vary materially from the forward market prices set forth in the preceding table.

EMMT engages in hedging activities for the coal plants to hedge the risk of future change in the price of electricity. The following table summarizes the hedge positions (including load requirements services contracts and forward contracts accounted for on the accrual basis) as of December 31, 2010 for electricity expected to be generated in 2011 and 2012:

	2011		2012	
	MWh (in thousands)	Average price/ MWh[1]	MWh (in thousands)	Average price/ MWh[1]
Midwest Generation plants				
Northern Illinois and AEP/Dayton Hubs	10,870	$ 37.75	3,358	$ 38.11
Homer City plant[2,3]				
PJM West Hub	2,540	55.36	1,370	51.68
Total	13,410		4,728	

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.

2 Includes hedging transactions primarily at the PJM West Hub and to a lesser extent at other trading locations. Years 2011 and 2012 include hedging activities entered into by EMMT for the Homer City plant that are not designated under the intercompany agreements with Homer City due to limitations under the sale leaseback transaction documents.

3 The average price/MWh includes 72 to 84 MW for periods ranging from January 1, 2011 to May 31, 2012 at Homer City sold in conjunction with load requirements services contracts.

Capacity Price Risk

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.

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The following table summarizes the status of capacity sales for Midwest Generation and Homer City at December 31, 2010:

	Installed Capacity	Unsold Capacity[1]	Capacity Sold[2]	RPM Capacity Sold in Base Residual Auction		Other Capacity Sales, Net of Purchases[3]		Aggregate Average Price per
					Price per		Average Price per	
	MW	MW	MW	MW	MW-day	MW	MW-day	MW-day
January 1, 2011 to May 31, 2011								
Midwest Generation	5,477	(548)	4,929	4,929	$ 174.29			$ 174.29
Homer City	1,884	(261)	1,623	1,813	174.29	(190)	$ 53.95	188.38
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	(232)	1,652	1,736	133.37	(84)	16.46	139.31
June 1, 2013 to May 31, 2014								
Midwest Generation	5,477	(827)	4,650	4,650	27.73			27.73
Homer City	1,884	(104)	1,780	1,780	226.15			221.03[4]

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 Excludes 72 to 84 MW of capacity for periods ranging from January 1, 2011 to May 31, 2012 at Homer City sold in conjunction with load requirements services contracts.

3 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.

4 Includes the impact of a 100 MW capacity swap transaction executed prior to the base residual auction at $135 per MW-day.

The RPM auction capacity prices for the delivery period of June 1, 2012 to May 31, 2013 and June 1, 2013 to May 31, 2014 varied between different areas of PJM. In the western portion of PJM, affecting Midwest Generation, the prices of $16.46 per MW-day and $27.73 per MW-day were substantially lower than other areas' capacity prices. The impact of lower capacity prices for these periods compared to previous years 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.

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 EMG 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.

Basis Risk

Sales made from the coal plants 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, EMG 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 plant and for settlement points at the Northern Illinois Hub and the AEP/Dayton Hub in the case of the Midwest Generation plants. EMG'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

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the difference. This is referred to as "basis risk." During 2010, transmission congestion in PJM resulted in prices at the Homer City busbar being lower than those at the PJM West Hub by an average of 14%, compared to 9% during 2009 and 16% during 2008. During 2010, transmission congestion in PJM 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 13% and 1%, respectively, compared to 14% and 1%, respectively, during 2009.

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, EMG is exposed to basis risk as described above. In order to mitigate basis risk, EMG 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, EMG'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 plant purchase coal primarily from the Southern PRB of Wyoming and from mines located near the facilities in Pennsylvania, respectively. Coal purchases are made under a variety of supply agreements. The following table summarizes the amount of coal under contract at December 31, 2010 for the following three years:

	Amount of Coal Under Contract in Millions of Equivalent Tons[1]		
	2011	**2012**	**2013**
Midwest Generation plants[2]	15.9	9.8	
Homer City plant	4.6	1.8	0.5

1 The amount of coal under contract in equivalent 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 plant.

2 In January 2011, Midwest Generation entered into additional contractual agreements for the purchase of 1.25 million tons for 2011.

EMG 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 plant, increased during 2010 from 2009 and decreased during 2009 from 2008. The market price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content) increased to a price of $70 per ton at December 31, 2010, compared to a price of $52.50 per ton at December 31, 2009, as reported by the EIA. In 2010, the price of NAPP coal ranged from $54 per ton to $71 per ton, as reported by the EIA. The 2010 increase in NAPP coal prices was primarily driven by the export market demand and global coal pricing.

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 increased during 2010 from 2009 year-end prices and declined during 2009 from 2008 year-end prices. The price of PRB coal fluctuated between $9.80 per ton and $15.35 per ton during 2010, with a price of $13.60 per ton at December 31, 2010, compared to a price of $9.25 per ton at December 31, 2009, as reported by the EIA. The 2010 increase in PRB coal prices was due to the draw down of inventory levels and flat to slight declines of PRB coal production.

EMG has contracts 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. EMG is exposed to price risk related to transportation rates after the expiration of its existing transportation contracts. Current market transportation rates for PRB coal 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 EMG's anticipated coal requirements in 2011 in excess of the amount under contract, EMG expects that a 10% change in the price of coal at December 31, 2010 would increase or decrease pre-tax income in 2011 by approximately $6 million.

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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, the coal plants are required to hold seasonal and annual NO_x allowances.

In the event that actual emissions required are greater than allowances held, EMG 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 $50 per ton in 2010, $65 per ton in 2009 and $315 per ton in 2008. The average purchase price of annual NO_x allowances was $936 per ton in 2010 and $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 $9 per ton and $320 per ton, respectively, at December 31, 2010.

Based on EMG's anticipated SO_2 requirements and annual and seasonal NO_x requirements for 2011 beyond those allowances already purchased, EMG expects that a 10% change in the price of SO_2 emission allowances and annual and seasonal NO_x emission allowances at December 31, 2010 would increase or decrease pre-tax income in 2011 by approximately $0.5 million.

Credit Risk

For further information related to credit risk and how EMG manages credit risk, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Derivative Instruments and Hedging Activities."

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. EMG'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, 2010, the balance sheet exposure as described above, broken down by the credit ratings of EMG's counterparties, was as follows:

	December 31, 2010		
(in millions)	**Exposure[2]**	**Collateral**	**Net Exposure**
Credit Rating[1]			
A or higher	$ 141	$ (14)	$ 127
A-	2		2
BBB+	4		4
BBB	31		31
BBB-	34		34
Below investment grade	39	(38)	1
Total	$ 251	$ (52)	$ 199

1 EMG 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 $149 million of net accounts receivable and payables and $102 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, EMG's subsidiaries have posted a $59 million cash margin in the aggregate with PJM, NYISO, Midwest Independent Transmission System Operator ("MISO"), clearing brokers and other counterparties to support hedging and trading activities. The margin posted to support these activities also exposes EMG to credit risk of the related entities.

The terms of EMG'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

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performance obligations and warranty agreements. EMG'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 EMG's turbine suppliers may have a material impact on EMG'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. A 10% change in market interest rates at December 31, 2010 would increase or decrease the fair value of the interest rate swap agreements by approximately $7 million. The fair market values of fixed interest rate obligations are subject to interest rate risk. The fair market value of EMG's consolidated long-term debt (including current portion) was $3.8 billion at December 31, 2010, compared to the carrying value of $4.5 billion. A 10% increase in market interest rates at December 31, 2010 would result in a decrease in the fair value of total long-term debt by approximately $167 million. A 10% decrease in market interest rates at December 31, 2010 would result in an increase in the fair value of total long-term debt by approximately $182 million.

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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 $(8) million, $18 million and $(29) million for 2010, 2009 and 2008, respectively. The decrease in 2010 earnings was primarily due to higher interest and general and administrative costs. The increase in 2009 earnings was primarily 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

Edison International Parent liquidity and its ability to pay operating expenses and dividends to common shareholders is dependent on dividends from SCE, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to bank and capital markets.

At December 31, 2010, Edison International (parent) had approximately $21 million of cash and equivalents on hand. The following table summarizes the status of the Edison International (parent) credit facility at December 31, 2010:

(in millions)	Edison International (parent)
Commitment	$ 1,426
Outstanding borrowings	(19)
Outstanding letters of credit	
Amount available	$ 1,407

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. At December 31, 2010, Edison International's consolidated debt to total capitalization ratio was 0.53 to 1.

Historical Cash Flows

The table below sets forth condensed historical cash flow information for Edison International Parent and Other.

Condensed Statement of Cash Flows

(in millions)	2010	2009	2008
Net cash used by operating activities	$ (218)	$ (32)	$ (3)
Net cash provided (used) by financing activities	214	(273)	290
Net cash provided (used) by investing activities	11	(2)	6
Net increase (decrease) in cash and cash equivalents	$ 7	$ (307)	$ 293

Net Cash Used by Operating Activities

Net cash used by operating activities primarily relate to interest, operating costs and income taxes of Edison International (parent). In addition to these factors, Edison International received $134 million in state tax refunds related to Global Settlement and made tax-allocation payments to SCE of $295 million, resulting in a use of operating cash flows during 2010. Edison International funded a portion of the 2010 tax-allocation payments due by Edison Capital in consideration for repayment of intercompany loans.

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See "Item 8. Edison International Notes to Consolidated Financial Statements Note 7. Income Taxes" for further discussion of the Global Settlement.

Net Cash Provided (Used) by Financing Activities

Financing activities for 2010 were as follows:

- Issued $400 million of senior notes due in 2017. The proceeds from these bonds were used to repay short-term borrowings under the revolving credit facility and the remainder for corporate liquidity purposes.
- Paid $411 million of dividends (or $0.315 per share quarterly) to Edison International common shareholders. These quarterly dividends represent an increase of $0.005 per share over quarterly dividends paid in 2009. In December 2010, the Board of Directors of Edison International declared a $0.32 per share quarterly dividend which was paid in January 2011. This quarterly dividend represents an increase of $0.005 per share over quarterly dividends paid in 2010.
- Received $300 million of dividend payments from SCE.
- Repaid a net $66 million of short-term debt.

Financing activities for 2009 were as follows:

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

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.

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EDISON INTERNATIONAL (CONSOLIDATED)

LIQUIDITY AND CAPITAL RESOURCES

Potential Regulation of Swaps under the Dodd-Frank Act

The Dodd-Frank Act provides the Commodity Futures Trading Commission and the SEC ("Agencies") with jurisdiction to regulate financial derivative products, including swaps, options and other derivative products ("Swaps"). The Agencies are required to issue rules and regulations that implement regulation of Swaps markets by July 2011.

The Dodd-Frank Act subjects Swaps to new mandatory clearing and trading requirements, if no exemption applies. It may also impose capital requirements on non-exempt market participants. The clearing and trading requirements could result in increased margining requirements which may increase the costs of hedging activity. SCE uses Swap transactions to hedge commodity price risk and is subject to oversight by the CPUC. EMG and its subsidiaries, particularly EMMT, use Swap transactions to hedge commercial risks associated with the generation, purchase and sale of electricity and fuel to wholesale customers. In addition, EMMT utilizes Swaps as part of its proprietary trading business.

If new clearing, trading or other requirements are applicable to EMG and SCE under the Dodd-Frank Act rules and regulations, the potential impact will depend on the content of those rules and regulations, which remains uncertain.

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Contractual Obligations

Edison International's contractual obligations as of December 31, 2010, for the years 2011 through 2015 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]	$ 22,843	$ 763	$ 2,027	$ 2,941	$ 17,112
Power purchase agreements[2]					
Renewable energy contracts	13,676	340	1,062	1,267	11,007
Qualifying facility contracts	3,723	429	822	809	1,663
Other power purchase agreements	6,354	548	1,364	1,105	3,337
Power plant and other operating lease obligations[3]	3,694	400	780	592	1,922
Purchase obligations:[4]					
Fuel supply contract payments	2,349	742	650	309	648
Coal transportation agreements	231	231			
Gas transportation agreements	60	8	16	17	19
Capital expenditure	182	182			
Turbine commitments	90	90			
Other contractual obligations	232	90	116	21	5
Employee benefit plans contributions[5]	867	183	449	235	
Total[6,7]	$ 54,301	$ 4,006	$ 7,286	$ 7,296	$ 35,713

1 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 5. Debt and Credit Agreements." Amount includes interest payments totaling $10.4 billion over applicable period of the debt.

2 Some of the power purchase agreements entered into with independent power producers are treated as operating leases and capital leases. At December 31, 2010, minimum operating lease payments for power purchase agreements were $740 million in 2011, $717 million in 2012, $761 million in 2013, $708 million in 2014, $693 million in 2015, and $8.7 billion for the thereafter period. At December 31, 2010, minimum capital lease payments for power purchase agreements were $33 million in 2011, $71 million 2012, $131 million for 2013, $153 million for 2014, $154 million for 2015, and $2.5 billion for the thereafter period (amounts include executory costs and interest of $628 million and $1.2 billion, respectively). For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

3 At December 31, 2010, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet stations and Homer City facilities and vehicles, office space and other equipment. For further discussion, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

4 For additional details, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 9. Commitments and Contingencies."

5 Amount includes estimated contributions to the pension and PBOP plans for SCE. These amounts represent estimates that are based on assumptions that are subject to change. The estimated contributions for SCE are not available beyond 2014. The estimated contributions for all other entities are not available beyond 2011. See "Item 8. Edison International Notes to Consolidated Financial Statements Note 8. Compensation and Benefit Plans" for further information.

6 At December 31, 2010, Edison International had a total net liability recorded for uncertain tax positions of $552 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 6. Derivative Instruments and Hedging Activities," and "Item 8. Edison International Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment," 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

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International's accounting policies, see "Item 8. Edison International 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 ratemaking 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, 2010, the consolidated balance sheets included regulatory assets of $4.7 billion and regulatory liabilities of $5.3 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. As described in "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. Derivative Instruments and Hedging Activities," SCE and EMG use derivative instruments to manage exposure to changes in electricity and fuel prices and interest rates. Derivative instruments are recorded at fair value unless certain exceptions are met in which case the derivative is recorded on an accrual basis.

SCE records derivative instruments that do not meet the normal purchases and sales exception at fair value with an offsetting regulatory asset or liability due to application of principles for rate-regulated enterprises. As a result, changes in fair value of SCE derivative instruments have no impact on earnings, but may temporarily affect cash flows. SCE has not elected to use hedge accounting for these transactions due to the regulatory accounting treatment.

EMG records derivative instruments that do not meet the normal purchases and sales exception at fair value, with changes in the derivative's fair value recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for cash flow hedge accounting treatment, the effective portion of the changes in the derivative's fair value is recognized in other comprehensive income until the hedged item is recognized in earnings. EMG records derivative instruments used for trading at fair value with changes in fair value recognized in income.

Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions.

Key Assumptions and Approach Used. SCE and EMG determine the fair value of derivative instruments 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, SCE and EMG review 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 4. 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, 2010, SCE and EMG Level 3 derivatives had a net fair value of $6 million and $91 million, respectively. While it is difficult to determine the impact of a change in any one input, if the fair value of SCE and EMG Level 3 derivatives were increased or decreased by 10%, the impact would be a less than $1 million and a $10 million increase or decrease to operating revenues, respectively. For 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 Disclosures" and "SCE: Market Risk Exposures Fair Value of Derivative Instruments." For further information on derivative instruments, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 6. 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 2008 and 2007 for San Onofre and Palo Verde, respectively, which estimate that SCE will spend approximately $8.6 billion through 2053 to decommission its active nuclear facilities. Decommissioning cost estimates are updated in each Nuclear Decommissioning Triennial Proceeding. The current estimate is based on the following assumptions from the 2008 and 2007 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 1.8% to 6.9% (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 2025, 2026 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

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by 2051 and 2053, respectively. Costs for spent fuel monitoring are included until 2051 and 2053, 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 $2.4 billion and $3.1 billion at December 31, 2010 and 2009, respectively. The ARO liability decrease in 2010 was mainly due to a decrease in escalation rates. 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 effect on the recorded liability and related regulatory asset. The following table illustrates the increase to the ARO and regulatory asset if the escalation rate was adjusted while leaving all other assumptions constant:

(in millions)	**Increase to ARO and regulatory asset at December 31, 2010**
Uniform increase in escalation rate of 25 basis points	$ 540

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.

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As of December 31, 2010, Edison International's pension plans had a $4.1 billion benefit obligation and total expense for these plans was $127 million for 2010. As of December 31, 2010, Edison International's PBOP plans had a $2.4 billion benefit obligation and total expense for these plans was $61 million for 2010. The following are critical assumptions used to determine expense for pension and other postretirement benefit for 2010:

(in millions)	Pension Plans	Postretirement Benefits Other than Pensions
Discount rate[1]	6.0%	6.0%
Expected long-term return on plan assets[2]	7.5%	7.0%
Assumed health care cost trend rates[3]		8.25%

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 15.4%, 4.6% and 5.1% for the one-year, five-year and ten-year periods ended December 31, 2010, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 12.9%, 3.1%, and 3.2% 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 gradually declines 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 ratemaking 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 ratemaking 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, 2010, this cumulative difference amounted to a regulatory asset of $77 million, meaning that the accounting method has recognized more in expense than the ratemaking 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 effect 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.

A one percentage point increase in the discount rate would decrease the projected benefit obligation for pension by $341 million. A one percentage point decrease in the discount rate would increase the projected benefit obligation for pension by $367 million. A one percentage point increase in the expected rate of return on pension plan assets would decrease the expense by $28 million.

A one percentage point increase in the discount rate for PBOP would decrease the projected benefit obligation by $303 million. A one percentage point decrease in the discount rate for the PBOP would increase the projected benefit obligation by $352 million. A one percentage point increase in the expected rate of return on PBOP plan assets would decrease the expense by $15 million. Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2010 by $284 million and annual aggregate service and interest costs by $17 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2010 by $237 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 7. Income Taxes" for a further discussion on income taxes.

Impairment of Long-Lived Assets

Nature of Estimates Required. Long-lived assets, including intangible assets, are evaluated for impairment in accordance with applicable authoritative guidance. 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. 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. Long-lived assets for impairment are evaluated whenever indicators of impairment exist or when there is a commitment to sell or dispose of 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.

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 are considered 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

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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.

Application to EMG's Merchant Coal-Fired Power Plants

Weak commodity prices combined with continuing, heightened public policy pressure on coal generation have resulted in continuing uncertainties for merchant coal-fired power plants, which may require significant capital and increased operating costs to meet environmental requirements. For a discussion of environmental requirements, see "Item 8. Edison International Notes to Consolidated Financial Statements Note 10. Regulatory and Environmental Developments" Management has reviewed long-term cash flow forecasts that include 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 include:

- 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 revenues as a result of declines in reserve margins beyond the price of the latest auctions; and
- Plans for compliance with both existing and possible future environmental regulations.

If electricity and capacity prices do not increase consistent with the fundamental forecast or if EMG 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 and impairment may result.

EMG includes allocated acquired emission allowances as part of each power plant asset group. In the case of the Powerton and Joliet Stations, EMG also includes prepaid rent in the respective asset group. EMG'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.

The following table summarizes the net book value of the merchant coal-fired asset groups at December 31, 2010:

(in millions)

Midwest Generation plants	
Crawford Station	$ 178
Fisk Station	124
Joliet Station	683
Powerton Station	721
Waukegan Station	365
Will County Station	537
Homer City plant	$ 978

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.

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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 9. Commitments and Contingencies."

New Accounting Guidance

New accounting guidance is 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."

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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 consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Edison International (the "Company") and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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 and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, 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 Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities and fair value disclosure principles as of January 1, 2010.

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
February 28, 2011

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Consolidated Statements of Income **Edison International**

(in millions, except per-share amounts)	Years ended December 31, 2010	2009	2008
Electric utility	$ 9,980	$ 9,962	$ 11,246
Competitive power generation	2,429	2,399	2,866
Total operating revenue	12,409	12,361	14,112
Fuel	1,172	1,517	2,147
Purchased power	2,930	2,751	3,845
Operations and maintenance	4,612	4,387	4,288
Depreciation, decommissioning and amortization	1,522	1,418	1,313
Lease terminations and other	47	890	(44)
Total operating expenses	10,283	10,963	11,549
Operating income	2,126	1,398	2,563
Interest and dividend income	31	32	62
Equity in income from partnerships and unconsolidated subsidiaries net	106	42	31
Other income	148	171	113
Interest expense net of amounts capitalized	(703)	(732)	(700)
Other expenses	(51)	(57)	(125)
Income from continuing operations before income taxes	1,657	854	1,944
Income tax expense (benefit)	354	(98)	596
Income from continuing operations	1,303	952	1,348
Income (loss) from discontinued operations net of tax	4	(7)	
Net income	1,307	945	1,348
Less: Dividends on preferred and preference stock of utility	52	51	51
Other noncontrolling interests	(1)	45	82
Net income attributable to Edison International common shareholders	$ 1,256	$ 849	$ 1,215
Amounts attributable to Edison International common shareholders:			
Income from continuing operations, net of tax	$ 1,252	$ 856	$ 1,215
Income (loss) from discontinued operations, net of tax	4	(7)	
Net income attributable to Edison International common shareholders	$ 1,256	$ 849	$ 1,215
Basic earnings per common share attributable to Edison International common shareholders:			
Weighted-average shares of common stock outstanding	326	326	326
Continuing operations	$ 3.83	$ 2.61	$ 3.69
Discontinued operations	0.01	(0.02)	
Total	$ 3.84	$ 2.59	$ 3.69
Diluted earnings per common share attributable to Edison International common shareholders:			

Weighted-average shares of common stock outstanding, including effect of dilutive securities		329		327		329
Continuing operations	$	3.81	$	2.60	$	3.68
Discontinued operations		0.01		(0.02)		
Total	$	3.82	$	2.58	$	3.68
Dividends declared per common share	$	1.265	$	1.245	$	1.225

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

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Consolidated Statements of Comprehensive Income **Edison International**

(in millions)	Years ended December 31, 2010	2009	2008
Net income	$ 1,307	$ 945	$ 1,348
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments net		4	(3)
Pension and postretirement benefits other than pensions:			
Net loss arising during the period	(23)	(13)	(36)
Amortization of net (gain) loss included in net income	6	13	
Prior service credit arising during the period	(6)		(1)
Amortization of prior service cost (credit)	(1)	1	(1)
Unrealized gain (loss) on derivatives qualified as cash flow hedges:			
Unrealized holding gain arising during the period, net of income tax expense of $37, $36 and $138 for 2010, 2009 and 2008, respectively	55	43	211
Reclassification adjustments included in net income, net of income tax expense (benefit) of $(96), $(124) and $58 for 2010, 2009 and 2008, respectively	(144)	(178)	89
Other comprehensive income (loss)	(113)	(130)	259
Comprehensive income	1,194	815	1,607
Less: Comprehensive income attributable to noncontrolling interests	51	96	133
Comprehensive income attributable to Edison International	$ 1,143	$ 719	$ 1,474

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

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Edison International

Consolidated Balance Sheets

(in millions)	**December 31, 2010**	**2009**
ASSETS		
Cash and cash equivalents	$ 1,389	$ 1,673
Receivables, less allowances of $85 and $53 for uncollectible accounts at respective dates	931	1,017
Accrued unbilled revenue	442	347
Inventory	568	533
Prepaid taxes	390	33
Derivative assets	133	357
Restricted cash	2	69
Margin and collateral deposits	65	125
Regulatory assets	378	120
Other current assets	124	156
Total current assets	4,422	4,430
Nuclear decommissioning trusts	3,480	3,140
Investments in partnerships and unconsolidated subsidiaries	559	216
Other investments	223	251
Total investments	4,262	3,607
Utility property, plant and equipment, net	24,778	21,966
Competitive power generation and other property, plant and equipment, net	5,406	5,147
Total property, plant and equipment	30,184	27,113
Derivative assets	437	268
Restricted deposits	47	43
Rent payments in excess of levelized rent expense under plant operating leases	1,187	1,038
Regulatory assets	4,347	4,139
Other long-term assets	644	806
Total long-term assets	6,662	6,294
Total assets	$ 45,530	$ 41,444

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

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Edison International

Consolidated Balance Sheets

(in millions, except share amounts)	**December 31, 2010**	**2009**
LIABILITIES AND EQUITY		
Short-term debt	$ 115	$ 85
Current portion of long-term debt	48	377
Accounts payable	1,362	1,347
Accrued taxes	52	186
Accrued interest	205	196
Customer deposits	217	238
Derivative liabilities	217	107
Regulatory liabilities	738	367
Other current liabilities	998	884
Total current liabilities	3,952	3,787
Long-term debt	12,371	10,437
Deferred income taxes	5,625	4,334
Deferred investment tax credits	122	102
Customer advances	112	119
Derivative liabilities	468	529
Pensions and benefits	2,260	2,061
Asset retirement obligations	2,561	3,241
Regulatory liabilities	4,524	3,328
Other deferred credits and other long-term liabilities	2,041	2,500
Total deferred credits and other liabilities	17,713	16,214
Total liabilities	34,036	30,438
Commitments and contingencies (Note 9)		
Common stock, no par value (800,000,000 shares authorized; 325,811,206 shares issued and outstanding at each date)	2,331	2,304
Accumulated other comprehensive income (loss)	(76)	37
Retained earnings	8,328	7,500
Total Edison International's common shareholders' equity	10,583	9,841
Preferred and preference stock of utility	907	907
Other noncontrolling interests	4	258
Total noncontrolling interests	911	1,165
Total equity	11,494	11,006
Total liabilities and equity	$ 45,530	$ 41,444

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

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Consolidated Statements of Cash Flows **Edison International**

(in millions)	Years ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income	$ 1,307	$ 945	$ 1,348
Less: Income (loss) from discontinued operations	4	(7)	
Income from continuing operations	1,303	952	1,348
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	1,522	1,418	1,313
Regulatory impacts of net nuclear decommissioning trust earnings (reflected in accumulated depreciation)	189	158	(10)
Other amortization	118	120	106
Lease terminations and other	47	888	(44)
Stock-based compensation	30	22	34
Equity in income from partnerships and unconsolidated subsidiaries net	(106)	(42)	(31)
Distributions and dividends from unconsolidated entities	92	31	(8)
Deferred income taxes and investment tax credits	1,139	(1,457)	207
Proceeds from U.S. Treasury grants	92		
Income from leveraged leases	(5)	(14)	(51)
Changes in operating assets and liabilities:			
Receivables	(155)	80	128
Inventory	(49)	20	(114)
Restricted cash	68	(69)	
Margin and collateral deposits net of collateral received	63	30	(19)
Prepaid taxes	(357)	178	(66)
Other current assets	(92)	24	18
Rent payments in excess of levelized rent expense	(149)	(160)	(162)
Accounts payable	(3)	152	(160)
Accrued taxes	(135)	(402)	340
Other current liabilities	13	31	(39)
Derivative assets and liabilities net	(44)	(581)	849
Regulatory assets and liabilities net	278	1,457	(2,946)
Other assets	(71)	62	224
Other liabilities	(315)	154	1,344
Operating cash flows from discontinued operations	4	(7)	
Net cash provided by operating activities	3,477	3,045	2,261
Cash flows from financing activities:			
Long-term debt issued	1,936	939	2,632
Long-term debt issuance costs	(38)	(25)	(21)
Long-term debt repaid	(396)	(1,044)	(295)
Bonds repurchased		(219)	(212)
Preferred stock redeemed			(7)
Short-term debt financing net	30	(2,058)	1,643
Settlements of stock-based compensation net	(16)	(3)	(26)
Cash contributions from noncontrolling interests		2	12
Dividends and distributions to noncontrolling interests	(52)	(117)	(170)
Dividends paid	(411)	(404)	(397)

Net cash provided (used) by financing activities	$ 1,053	$ (2,929)	$ 3,159

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

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Consolidated Statements of Cash Flows **Edison International**

(in millions)	Years ended December 31, 2010	2009	2008
Cash flows from investing activities:			
Capital expenditures	$ (4,543)	$ (3,282)	$ (2,824)
Purchase of interest in acquired companies	(4)	(22)	(19)
Proceeds from termination of leases		1,420	
Proceeds from sale of property and interests in projects	2	7	113
Proceeds from sale of nuclear decommissioning trust investments	1,432	2,217	3,130
Purchases of nuclear decommissioning trust investments and other	(1,651)	(2,416)	(3,137)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment	44	11	65
Maturities and sale of short-term investments	7	4	96
Purchase of short-term investments	(4)	(7)	(22)
Investments in other assets	(6)	(291)	(347)
Effect of consolidation and deconsolidation of variable interest entities	(91)		
Net cash used by investing activities	(4,814)	(2,359)	(2,945)
Net increase (decrease) in cash and cash equivalents	(284)	(2,243)	2,475
Cash and cash equivalents, beginning of year	1,673	3,916	1,441
Cash and cash equivalents, end of year	$ 1,389	$ 1,673	$ 3,916

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

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Edison International

Consolidated Statements of Changes in Equity

	Equity Attributable to Edison International				Noncontrolling Interests		
(in millions)	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Subtotal	Other	Preferred and Preference Stock	Total Equity
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
Net income (loss)			1,256	1,256	(1)	52	1,307
Other comprehensive loss		(113)		(113)			(113)
Deconsolidation of variable interest entities (See Note 3)					(249)		(249)
Cumulative effect of a change in accounting principle, net of tax			15	15			15
Common stock dividends declared ($1.265 per share)			(412)	(412)			(412)
Dividends, distributions to noncontrolling interests and other					(4)	(52)	(56)
Stock-based compensation net	8		(24)	(16)			(16)
Noncash stock-based compensation and other	19		(7)	12			12
Balance at December 31, 2010	$ 2,331	$ (76)	$ 8,328	$ 10,583	$ 4	$ 907	$ 11,494

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

Edison International has two business segments for financial reporting purposes: an electric utility operation segment (SCE) and a competitive power generation segment (EMG). SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to an approximately 50,000-square-mile area of southern California. EMG is the holding company for its principal wholly owned subsidiary, EME. 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 engages in hedging and energy trading activities in competitive power markets through its Edison Mission Marketing & Trading, Inc. ("EMMT") subsidiary.

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 Variable Interest Entities ("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 EMG'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 ratemaking 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. Regulators may also impose certain penalties or grant certain incentives. 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 require 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. SCE assesses, at the end of each reporting period, whether regulatory assets are probable of future recovery. See Note 14 for composition of regulatory assets and liabilities.

The preparation of financial statements in conformity with United States generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results could differ from those estimates.

Certain prior year reclassifications have been made to conform to the current year financial statement presentation.

Cash Equivalents

Cash equivalents included investments in money market funds totaling $1.1 billion and $1.5 billion at December 31, 2010 and 2009, respectively. Generally, the carrying value of cash equivalents equals the fair value, as all investments have maturities of three months or less.

Edison International temporarily invests the ending daily cash balance in its primary disbursement accounts until required for check clearing. Edison International reclassified $197 million and $224 million of checks issued against these accounts, but not yet paid by the financial institution, from cash to accounts payable at December 31, 2010 and 2009, 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, debt service or to provide collateral. Included in restricted deposits was $20 million at both December 31, 2010 and 2009 related to lease payments and $27 million and $23 million at December 31, 2010 and 2009, respectively, related to debt service and collateral reserves, or other.

Allowance for Uncollectible Accounts

SCE records an allowance for uncollectible accounts, generally determined by the average percentage of amounts written-off in prior periods. Generally, 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.

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 consisted of the following:

	December 31,	
(in millions)	**2010**	**2009**
Coal, gas, fuel oil and other raw materials	$ 184	$ 158
Spare parts, materials and supplies	384	375
Total inventory	$ 568	$ 533

Property, Plant and Equipment

Utility Property, Plant and Equipment

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. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the ratemaking 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	46 years
Other plant	5 years to 60 years	22 years

Depreciation of utility property, plant and equipment 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, 4.1%, 4.2% and 4.3% for 2010, 2009 and 2008, respectively. 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.

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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 ratemaking procedures. Nuclear fuel is amortized using the units of production method.

AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction and is capitalized during certain plant construction. 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 $100 million, $116 million and $54 million in 2010, 2009 and 2008, respectively, and AFUDC debt was $41 million, $32 million and $27 million in 2010, 2009 and 2008, respectively.

The 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 several of SCE's transmission projects. 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.

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 EMG's majority-owned subsidiaries' plants and related facilities and, prior to January 1, 2010, the plant and related facilities of VIEs consolidated by SCE. Depreciation and amortization are computed using the straight-line method over the estimated useful life of the property, plant and equipment and over the shorter of the lease term or estimated useful life for leasehold improvements. Gains and losses from sale of assets are recognized at the time of the transaction.

As part of the acquisition of the Midwest Generation plants and the Homer City plant, EMG acquired emission allowances under the United States Environmental Protection Agency's (US EPA's) Acid Rain Program. EMG uses these emission allowances in the normal course of its business to generate electricity and has classified them as part of property, plant and equipment. Acquired emission allowances will be amortized on a straight-line basis.

Estimated useful lives for property, plant and equipment are as follows:

Power plant facilities	3 to 35 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 10 years
Capitalized leased equipment	5 years

Interest incurred on funds borrowed by EMG is capitalized during the construction period. 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. Capitalized interest was $54 million, $19 million and $32 million in 2010, 2009 and 2008, respectively.

Major Maintenance

Certain of Edison International's power plant facilities and equipment require periodic major maintenance. These costs are expensed as incurred.

Asset Retirement Obligation

The fair value of a liability for an asset retirement obligation ("AROs") is recorded in the period in which it is incurred, including a liability for the fair value of a conditional ARO, if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. When an ARO liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased for accretion expense 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 an increase or decrease in expense. AROs related to decommissioning of SCE's nuclear power facilities are based on site-specific studies. Those site-specific studies are updated with each Nuclear Decommissioning Cost Triennial Proceeding ("NDCTP"). The initial establishment of a nuclear-related ARO is at fair value. Subsequent layers of an ARO are established for updated site-specific decommissioning cost estimates stemming from the approved NDCTP. For further discussion, see "Nuclear Decommissioning" below and see Notes 4 and 15. A reconciliation of the changes in the ARO liability is as follows:

(in millions)	**2010**	**2009**
Beginning balance	$ 3,241	$ 3,042
Accretion expense	198	188
Revisions[1]	(867)	6
Liabilities added	9	6
Liabilities settled	(1)	(1)
Transfers in or out[2]	(19)	
Ending balance	$ 2,561	$ 3,241

1 Revisions represent the most recent site-specific studies approved by the CPUC in 2010.

2 Transfers in or out consist of the deconsolidation of the Big 4 projects and two wind projects, and consolidation of one coal project effective January 1, 2010. For further details, see Note 3.

The ARO liability as of December 31, 2010 includes $2.4 billion related to nuclear decommissioning.

Impairment of 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 that the carrying amount of such investments or assets may not be recoverable. If the carrying amount of a long-lived asset exceeds expected future cash flows, undiscounted and without interest charges, an impairment loss is recognized in the amount of the excess of fair value over the carrying amount. SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from ratepayers.

Project Development Costs

Edison International capitalizes project development costs incurred in the assessment, design and construction of generating projects once it is probable that the project will be completed. Edison International determines it is probable that the project will be completed based upon management's determination that the project is economically and operationally feasible and appropriate management and regulatory approvals have been obtained or are probable. Project development costs consist of professional fees, permits and other directly related development costs incurred by Edison International. The capitalized costs are recorded in other long-term assets on Edison International's consolidated balance sheets until the start of construction, at which time the costs are transferred to construction in progress, a component of property, plant and equipment. The capitalized costs are amortized over the life of the projects once operational or charged to expense if management determines the costs to be unrecoverable.

Leases

Power purchase agreements entered into by SCE and EMG may contain leases as described under "Power Purchase Agreements" below. EMG leases the Homer City, Powerton and a portion of the Joliet's power plants under sales leaseback arrangements as described in Note 9. Both SCE and EMG have entered into a number of agreements to lease property and equipment in the normal course of business. 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 in "Other deferred credits and other long-term liabilities." As a rate-regulated enterprise, SCE's capital lease amortization expense and interest expense are reflected in "Purchased power" on the consolidated statements of income.

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Nuclear Decommissioning

In 2003, SCE recorded the fair value of its liability for AROs related to the decommissioning of its nuclear power facilities. 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 ratemaking process. Decommissioning cost estimates are updated in each 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.

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, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments primarily consist of debt and equity investments that are classified as available-for-sale. 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 assets 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 on the last day of each month. If the fair value on the last day of two consecutive months 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.

Deferred Financing Costs

Debt premium, discount and issuance expenses incurred in connection with obtaining financing are deferred and amortized on a straight-line basis for SCE and on a basis which approximates the effective interest rate method for EMG as interest expense over the term of the related debt. Under CPUC ratemaking 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 losses on reacquired debt of $268 million and $287 million at December 31, 2010 and 2009, respectively, reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. Edison International had unamortized debt issuance costs of $114 million and $93 million at December 31, 2010 and 2009, respectively, reflected in "Other long-term assets" on the consolidated balance sheets. Amortization of deferred financing costs charged to interest expense was $35 million, $31 million and $28 million in 2010, 2009 and 2008, respectively.

Revenue Recognition

Electric Utility Revenue

Electric utility revenue is recognized when 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 the rate change is filed. Revenue collected prior to a final FERC approval decision is subject to refund.

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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 mechanisms allow differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers; and 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 ($1.2 billion, $1.8 billion and $2.2 billion in 2010, 2009 and 2008, respectively) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002 and expected to continue until 2022) and a portion of direct access exit fees (effective January 1, 2003 and expected to continue until 2022) are being remitted to the CDWR and are not recognized as electric utility revenue by SCE.

Competitive Power Generation Revenue

Generally, competitive power generation revenue and related costs are recognized when 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. EMG's subsidiaries enter into power and fuel hedging, optimization transactions and energy trading contracts, all subject to market conditions. One of EMG'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, EMG's subsidiaries generally act as the principal, take title to the commodities, and assume the risks and rewards of ownership. EMG's subsidiaries record the settlement of nontrading physical forward contracts on a gross basis. EMG 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, EMG'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 on Edison International's consolidated statements of income.

Competitive power generation revenues under certain long-term power sales contracts are recognized based on the output delivered at the lower of the amount billable or the average rate over the contract term. The excess of the amounts billed over the portion recorded as revenues is reflected in "Other deferred credits and other long-term liabilities" on the consolidated balance sheets.

EMG accounts for grant income on the deferred method and, accordingly, recognizes operating revenues related to such income over the estimated useful life of the projects. In 2010, EMG received $92 million in U.S. Treasury grants (cash grants, under the American Recovery and Reinvestment Act of 2009) related to wind projects that was included in "Receivables" on the consolidated balance sheets at December 31, 2009.

Power Purchase Agreements

Both SCE, generally as the purchaser, and EMG, generally as the seller, enter into long-term power purchase agreements in the normal course of business. Accounting for long-term power purchase agreements is complex and varies based on the terms and conditions of each agreement. A power purchase agreement may be considered a variable interest in a variable interest entity. Under this classification, the power purchase agreement is evaluated to determine if SCE or EMG is the primary beneficiary in the variable interest entity, in which case, such entity would be consolidated. None of SCE's or EMG's power purchase agreements resulted in consolidation of a variable interest entity at December 31, 2010. See Note 3 for further discussion of power purchase agreements that are considered variable interests.

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A power purchase agreement may also contain a lease for accounting purposes. This generally occurs when a power purchase agreement (signed or modified after June 30, 2003) designates a specific power plant in which the buyer purchases substantially all of the output and does not otherwise meet a fixed price per unit of output exception. SCE and EMG have a number of power purchase agreements that contain leases. EMG's revenue from these power sales agreements were $81 million, $83 million and $46 million in 2010, 2009 and 2008, respectively. SCE's recognition of lease expense conforms to the ratemaking treatment for SCE's recovery of the cost of electricity. These agreements are classified as operating leases as electricity is delivered at rates defined in power sales agreements. See Note 9 for further discussion of SCE's power purchase agreements, including agreements that are classified as capital leases for accounting purposes.

A power purchase agreement that does not contain a lease may be classified as a derivative subject to a normal purchase and sale exception, in which case the power purchase agreement is classified as an executory contract. 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 purchase and sale exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a normal gas index, but the power is not generated with natural gas. These contracts are not eligible for the normal purchase and sale exception and are recorded as a derivative on the consolidated balance sheets at fair value. See Note 6 for further information on derivatives and hedging activities.

Power purchase agreements that do not meet the above classification are accounted for on the accrual basis.

Derivative Instruments and Hedging Activities

Edison International records derivative instruments on its consolidated balance sheets as either assets or liabilities measured at fair value unless otherwise exempted from derivative treatment as normal purchases or sales. 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 regulatory accounting treatment.

EMG's changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met, which requires that EMG formally document, designate, and assess the effectiveness of hedge transactions. The accounting guidance for cash flow hedges provides that the effective portion of gains or losses on derivative instruments designated and qualifying as cash flow hedges be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gains or losses on the derivative instruments, if any, must be recognized currently in earnings.

Where Edison International's derivative instruments are subject to a master netting agreement and certain criteria are met, Edison International presents its derivative assets and liabilities on a net basis on its consolidated balance sheets. In addition, derivative positions are offset against margin and cash collateral deposits. The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows. See Note 6 for further information on derivative and hedging activities.

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, $102 million and $103 million for the years ended December 31, 2010, 2009 and 2008, respectively. When SCE acts as an agent and when the tax is not required to be remitted as not having been collected from the customer, the taxes are accounted for

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on a net basis. Amounts billed to and collected from customers for these taxes are for remission to the taxing authorities and are not recognized as electric utility revenue.

Stock-Based Compensation

Stock options, performance shares, deferred stock units and 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 granted to management are settled in cash 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 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 is recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement.

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 sets 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, 2010, SCE's 13-month weighted-average common equity component of total capitalization was 51% resulting in the capacity to pay $497 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. EPS attributable to Edison International common shareholders was computed as follows:

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Basic earnings per share continuing operations:			
Income from continuing operations attributable to common shareholders, net of tax	$ 1,252	$ 856	$ 1,215
Gain on redemption of preferred stock			2
Participating securities dividends	(5)	(6)	(14)
Income from continuing operations available to common shareholders	$ 1,247	$ 850	$ 1,203
Weighted average common shares outstanding	326	326	326
Basic earnings per share continuing operations	$ 3.83	$ 2.61	$ 3.69
Diluted earnings per share continuing operations:			
Income from continuing operations available to common shareholders	$ 1,247	$ 850	$ 1,203
Income impact of assumed conversions	5	1	8
Income from continuing operations available to common shareholders and assumed conversions	$ 1,252	$ 851	$ 1,211
Weighted average common shares outstanding	326	326	326
Incremental shares from assumed conversions	3	1	3
Adjusted weighted average shares diluted	329	327	329
Diluted earnings per share continuing operations	$ 3.81	$ 2.60	$ 3.68

Stock-based compensation awards to purchase 5,981,090, 8,547,090 and 3,848,546 shares of common stock for the years ended December 31, 2010, 2009 and 2008, 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.

Income Taxes

Edison International estimates 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 "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 or the term of the power purchase agreement of the respective project while production tax credits are recognized in income tax expense in the period in which they are earned. EMG's investments in wind-powered electric generation projects qualify for federal production tax credits under Section 45 of the Internal Revenue Code. Such credits are allowable for production during the 10-year period after a qualifying wind energy facility is placed into service. Certain of EMG's wind projects also qualify for state tax credits, which are accounted for similarly to federal production tax credits.

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.

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Related Party Transactions

Four EMG 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. Sales by these partnerships to SCE under these agreements amounted to $367 million, $366 million and $686 million in 2010, 2009 and 2008, respectively.

An indirect wholly owned affiliate of EMG has entered into operation and maintenance agreements with partnerships in which EMG has a 50% or less ownership interest. EMG recorded power generation revenue under these agreements of $23 million, $26 million and $28 million in 2010, 2009 and 2008, respectively. EMG's accounts receivable with this affiliate totaled $5 million and $6 million at December 31, 2010 and 2009, respectively.

New Accounting Guidance

Accounting Guidance Adopted in 2010

Consolidation Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities

This Financial Accounting Standards Board ("FASB") update 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, its 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 or the right to receive expected returns of the entity. 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 adopted this guidance prospectively effective January 1, 2010. The impact of adopting this guidance resulted in the deconsolidation of assets totaling $683 million and the consolidation of assets totaling $99 million at January 1, 2010, and resulted in a cumulative effect adjustment which increased retained earnings by $15 million. For further discussion, see Note 3.

Fair Value Measurements and Disclosures

This FASB accounting standards update provides for new disclosure requirements related to fair value measurements. The requirements, which Edison International adopted effective January 1, 2010, include separate disclosure of significant transfers in and out of Levels 1 and 2 and the reasons for the transfers. The update also clarified existing disclosure requirements for the level of disaggregation, inputs and valuation techniques. Since this guidance impacts disclosures only, the adoption did not have an impact on Edison International's consolidated results of operations, financial position or cash flows. In addition, effective January 1, 2011, 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 guidance impacts disclosures only. For further discussion, see Note 4.

Accounting Guidance Not Yet Adopted

In October 2009, the FASB issued amended guidance for identifying separate deliverables in a revenue-generating transaction where multiple deliverables exist and guidance for allocating and recognizing revenues based on those separate deliverables. This update also requires additional disclosure related to the significant assumptions used to determine the revenue recognition of the separate deliverables. This guidance is effective beginning January 1, 2011 and is required to be applied prospectively to new or significantly modified revenue arrangements. The adoption of this accounting standards update will not have a material impact on Edison International's consolidated results of operations, financial position or cash flows.

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Note 2. Property, Plant and Equipment

Utility Property, Plant and Equipment

Utility property, plant and equipment included on the consolidated balance sheets is composed of the following:

	December 31,	
(in millions)	**2010**	**2009**
Transmission and distribution	$ 20,689	$ 19,192
Generation	3,371	2,743
General plant and other	3,377	2,946
Accumulated depreciation	(6,319)	(5,921)
	21,118	18,960
Construction work in progress	3,291	2,701
Nuclear fuel, at amortized cost	369	305
Total utility property, plant and equipment	$ 24,778	$ 21,966

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 these projects is reflected in the consolidated balance sheets and included in the above table. SCE's proportionate share of expenses for each project is reflected in the consolidated statements of income.

The following is SCE's investment in each project as of December 31, 2010:

(in millions)	**Investment in Facility**	**Accumulated Depreciation and Amortization**	**Ownership Interest**
Transmission systems:			
Eldorado	$ 74	$ 12	60%
Pacific Intertie	183	65	50%
Generating stations:			
Four Corners Units 4 and 5 (coal)	596	499	48%
Mohave (coal)	347	312	56%
Palo Verde (nuclear)	1,899	1,543	16%
San Onofre (nuclear)	5,369	4,080	78%
Total	$ 8,468	$ 6,511	

All of the investments in the Mohave generating station and a portion of the investments in San Onofre and Palo Verde generating stations are included in regulatory assets on the consolidated balance sheets see Note 14.

On November 8, 2010, SCE entered into an agreement to sell its ownership interest in Units 4 and 5 of the Four Corners coal-fired electric generating facility to the operator of the facility, Arizona Public Service Company. The sale price is $294 million, subject to certain adjustments. The closing of the sale is contingent upon the receipt of regulatory approvals and other specified closing conditions and is currently estimated to occur in the second half of 2012. Any gain on the sale will be for the benefit of SCE's ratepayers and, therefore, will not affect SCE's earnings.

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Competitive Power Generation and Other Property, Plant and Equipment

Competitive power generation and other property included on the consolidated balance sheets was composed of the plant and related facilities of EMG and prior to January 1, 2010 VIEs consolidated by SCE:

	December 31,	
(in millions)	**2010**	**2009**
Building, plant and equipment	$ 4,572	$ 5,192
Emission allowances	1,305	1,305
Leasehold improvements	177	156
Furniture and equipment	97	75
Land (including easements)	84	31
Construction in progress[1]	1,036	619
	7,271	7,378
Accumulated provision for depreciation	(1,865)	(2,231)
Competitive power generation and other property net	$ 5,406	$ 5,147

1 Construction in progress consisted of $888 million and $451 million at December 31, 2010 and 2009, respectively, related to wind projects.

The power sales agreements of certain wind projects are classified as operating leases. The carrying amount and related accumulated depreciation of the property of these wind projects totaled $1.4 billion and $137 million, respectively, at December 31, 2010.

Note 3. Variable Interest Entities

Effective January 1, 2010, Edison International adopted the FASB's new guidance regarding VIEs. A VIE is defined as a legal entity whose equity owners do not have sufficient equity at risk, or, as a group, the holders of the equity investment at risk lack any of the following three characteristics: decision-making rights, the obligation to absorb losses, or the right to receive the expected residual returns of the entity. Under this new qualitative model, the primary beneficiary is identified as the variable interest holder that has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE. Commercial and operating activities are generally the factors that most significantly impact the economic performance of VIEs in which Edison International has a variable interest. Commercial and operating activities include construction, operation and maintenance, fuel procurement, dispatch, and compliance with regulatory and contractual requirements.

Description of Use of Variable Interest Entities

EMG 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. EMG's subsidiaries or affiliates have typically been formed to own full or partial interests in one or more power generation facilities and ancillary facilities, with each plant or group of related plants being individually referred to by EMG as a project.

EMG's subsidiaries and affiliates have financed the development and construction or acquisition of its projects by capital contributions from EMG 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 secured by project specific assets and structured as non-recourse to EMG, with several exceptions, including EMG'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.

EMG, 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,

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the projects are managed and operated by unrelated parties and project debt is non-recourse to EMG. 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

EMG has purchased a majority interest in a number of wind projects under joint development agreements with third-party developers. At December 31, 2010 and 2009. EMG had majority interests in 15 wind projects with a total generating capacity of 700 MW that have minority interests held by others. The projects are located in Iowa, Minnesota, New Mexico, Nebraska and Texas. Upon the application of the new guidance effective January 1, 2010, EMG deconsolidated two of these projects. See further discussion in " Variable Interests in VIEs that are not Consolidated Equity Interests." In determining that EMG was the primary beneficiary of the 13 projects consolidated at December 31, 2010, the key factors considered were EMG's ability to direct commercial and operating activities and EMG's obligation to absorb losses and right to receive benefits that could potentially be significant to the variable interest entities.

The following table presents summarized financial information of the wind projects that were consolidated by Edison International:

	December 31,	
(in millions)	**2010**	**2009**
Current assets	$ 16	$ 73
Net property, plant and equipment[1]	660	944
Other long-term assets	2	2
Total assets[1]	$ 678	$ 1,019
Current liabilities	$ 11	$ 17
Long-term debt net of current maturities	16	20
Deferred revenues	57	58
Other long-term liabilities	19	21
Total liabilities	$ 103	$ 116
Noncontrolling interests	$ 4	$ 76

1 Amounts included assets of $253 million ($247 million of net property, plant and equipment) that were deconsolidated on January 1, 2010.

Assets serving as collateral for the debt obligations had a carrying value of $71 million and $81 million at December 31, 2010 and 2009, respectively, and primarily consist of property, plant and equipment. The consolidated statements of income and cash flows for the years ended December 31, 2010 and 2009 includes $13 million and $12 million of pre-tax losses, respectively, and $7 million and $37 million of operating cash flows, respectively, related to variable interest entities that are consolidated.

EMG has a 50% partnership interest in the Ambit project. EMG has the power to direct the commercial and operating activities of the project pursuant to the existing contracts and has the obligation to absorb losses and right to receive benefits from the project. Effective January 1, 2010 under new accounting guidance, EMG is the primary beneficiary. As the primary beneficiary, EMG consolidated Ambit project assets totaling $93 million and $99 million on December 31, and January 1, 2010.

Substantially all of the assets are pledged as collateral for the partnership's debt obligations.

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Variable Interest in VIEs that are not Consolidated

Power Purchase Contracts

SCE has 16 power purchase agreements ("PPAs") that are considered variable interests in VIEs, including 6 tolling agreements where SCE provides the natural gas to operate the plants and 10 contracts with QFs (including the Big 4 projects) that contain variable pricing provisions based on the price of natural gas. SCE has concluded that it is not the primary beneficiary of these VIEs since it does not control the commercial and operating activities of these entities. In general, because payments for capacity are the primary source of income, the most significant economic activity for SCE's VIEs is the operation and maintenance of the power plants. See further discussion of the Big 4 projects below.

As of the balance sheet date, the carrying amount of assets and liabilities in SCE's consolidated balance sheet that relate to its involvement with VIEs result from amounts due under the PPAs or the fair value of those derivative contracts, which are accounted for at fair value. SCE recovers the costs incurred under these contracts under its approved long-term power procurement plans. Further, SCE has no residual interest in the entities and has not provided or guaranteed any debt or equity support, liquidity arrangements, performance guarantees or other commitments associated with these contracts other than the purchase commitments described in Note 9, so there is no significant potential exposure to loss as a result of SCE's involvement with these VIEs. The aggregate capacity dedicated to SCE for these VIE projects was 3,820 MW at December 31, 2010 and the amounts that SCE paid to these projects were $534 million and $524 million for the years ended December 31, 2010 and 2009, respectively. These amounts are recoverable in customer rates.

Equity Interests

EMG accounts for domestic energy projects in which it has a 50% or less ownership interest, and cannot exercise unilateral control, under the equity method. As of December 31, 2010 and 2009, EMG had five significant variable interests in projects that are not consolidated, consisting of the Big 4 projects and the Sunrise project. A subsidiary of EMG operates the Big 4 projects and EMG's partner provides the fuel management services. In addition, the executive director of these projects is provided by EMG's partner. Commercial and operating activities are jointly controlled by a management committee of each variable interest entity. Accordingly, EMG continues to account for its variable interests under the equity method.

EMG deconsolidated two renewable wind energy generating facilities, the Elkhorn Ridge wind project and San Juan Mesa wind project, on January 1, 2010. The commercial and operating activities of these entities are directed by a management committee comprised of representatives of each partner. Thus, EMG is not the primary beneficiary of these projects. Accordingly, effective January 1, 2010, EMG accounts for its interests in these projects under the equity method.

The following table presents the carrying amount of EMG's investments in unconsolidated variable interest entities and the maximum exposure to loss for each investment:

	As of December 31, 2010	
(in millions)	**Investment**	**Maximum Exposure**
Natural gas-fired projects	$ 333	$ 333
Wind projects	224	224

EMG's maximum exposure to loss in its variable interest entities accounted for under the equity method is generally limited to its investment in these entities. Two of EMG's domestic energy projects have long-term debt that is collateralized by a pledge of assets of the project entity, but does not provide for recourse to EMG. 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 EMG's investment, but would not require EMG to contribute additional capital. At December 31, 2010, entities which EMG has accounted for under the equity method had indebtedness of $116 million, of which $41 million is proportionate to EMG's ownership interest in these two projects. At December 31, 2009, entities which EMG has accounted for under the equity method had indebtedness of $245 million, of which $104 million was proportionate to EMG's ownership interest in these two projects.

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EMG has also invested in affordable housing projects utilizing partnership or limited liability companies. With a few exceptions, an unrelated general partner or managing member exercises operating control of these projects. At December 31, 2010, projects that EMG has accounted for under the equity method had indebtedness of approximately $1.3 billion, of which approximately $451 million is proportionate to its ownership interest in these projects. At December 31, 2009, projects that EMG has accounted for under the equity method had indebtedness of approximately $1.5 billion, of which approximately $631 million is proportionate to its ownership interest in these projects. Substantially all of this debt is nonrecourse to Edison Capital.

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

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Revenues	$ 1,043	$ 581	$ 557
Expenses	934	506	534
Net income	$ 109	$ 75	$ 23

	December 31,	
(in millions)	**2010**	**2009**
Current assets	$ 352	$ 326
Noncurrent assets	2,437	2,344
Total assets	$ 2,789	$ 2,670
Current liabilities	$ 227	$ 188
Noncurrent liabilities	1,312	1,668
Equity	1,166	814
Total liabilities and equity	$ 2,705	$ 2,670

The difference between the carrying value of these equity investments and the underlying equity in the net assets was $11 million at December 31, 2010. The difference is being amortized over the life of the projects. The majority of noncurrent liabilities are comprised of project financing arrangements that are non-recourse to EMG. The undistributed earnings of equity method investments were $28 million and $30 million at December 31, 2010 and 2009, respectively.

In February 2010, EMG sold its 50% ownership interest in the March Point project to its partner after receiving an $18 million equity distribution reflected in "Equity in income from unconsolidated affiliates" on EMG's consolidated statement of income. The purchaser of EMG's interest in March Point has agreed to indemnify EMG for claims under a guarantee.

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The following table presents, as of December 31, 2010, the investments in unconsolidated affiliates accounted for by the equity method that represent at least five percent (5%) of EMG's income before tax or in which EMG has an investment balance greater than $50 million:

Unconsolidated Affiliates	Location	Investment at December 31, 2010 (in millions)	Ownership Interest at December 31, 2010	Operating Status
San Juan Mesa	Elida, NM	$ 92	75%	Operating wind-powered facility
Elkhorn Ridge	Bloomfield, NE	81	67%	Operating wind-powered facility
Sunrise	Fellows, CA	174	50%	Operating gas-fired facility
Midway-Sunset	Taft, CA	40	50%	Operating cogeneration facility
Sycamore	Bakersfield, CA	36	50%	Operating cogeneration facility
Kern River	Bakersfield, CA	26	50%	Operating cogeneration facility
Watson	Carson, CA	48	49%	Operating cogeneration facility

The following table presents summarized financial information of the investments in unconsolidated affiliates:

(in millions)	2010	2009
Investments in Unconsolidated Affiliates		
Equity investment	$ 550	$ 206
Cost investment	9	10
Total	$ 559	$ 216

Big 4 Projects Consolidated Prior to 2010

Edison International has variable interests in the Big 4 Projects through equity interests held by EMG and power contracts between SCE and the Big 4 Projects that contain variable contract pricing provisions based on the price of natural gas. Prior to 2010, Edison International had determined that SCE was the primary beneficiary of these four VIEs and, therefore, consolidated these projects. Edison International deconsolidated the Big 4 Projects at January 1, 2010 since it does not control the commercial and operating activities of these projects. Commercial and operating activities are jointly controlled by a management committee of each VIE. EMG's partner provides the executive director and fuel management services and the steam supply is based on the needs of EMG's partner. The deconsolidation did not result in a gain or loss.

The following table presents the carrying amounts of VIEs consolidated by Edison International at December 31, 2009 (these balances were deconsolidated at January 1, 2010):

(in millions)	December 31, 2009
Cash	$ 92
Other current assets	81
Competitive power generation and other property, plant and equipment net	253
Other long-term assets	4

Total assets	$	430
Current liabilities	$	64
Asset retirement obligations		17
Noncontrolling interests		349
Total liabilities and equity	$	430

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Note 4. Fair Value Measurements

Recurring 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 of an asset or liability should consider assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk.

Edison International categorizes financial assets and liabilities into a fair value hierarchy based on valuation inputs used to derive fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

The following table sets forth assets and liabilities that were accounted for at fair value by level within the fair value hierarchy.

	As of December 31, 2010				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting and Collateral[1]**	**Total**
Assets at Fair Value					
Money market funds[2]	$ 1,100	$	$	$	$ 1,100
Derivative contracts					
Electricity		70	363	(61)	372
Natural gas	1	69	11	(1)	80
Fuel oil	8			(8)	
Tolling			118		118
Subtotal of commodity contracts	9	139	492	(70)	570
Long-term disability plan	9				9
Nuclear decommissioning trusts					
Stocks[3]	2,029				2,029
Municipal bonds		790			790
Corporate bonds[4]		346			346
U.S. government and agency securities	215	73			288
Short-term investments, primarily cash equivalents[5]	1	31			32
Subtotal of nuclear decommissioning trusts	2,245	1,240			3,485
Total assets[6]	3,363	1,379	492	(70)	5,164
Liabilities at Fair Value					
Derivative contracts:					
Electricity		13	40	(21)	32
Natural gas		286	11	(4)	293
Tolling			344		344
Coal		1		(1)	
Subtotal of commodity contracts		300	395	(26)	669
Interest rate contracts		16			16
Total liabilities		316	395	(26)	685

Net assets (liabilities)	$	3,363	$	1,063	$	97	$	(44)	$	4,479

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	As of December 31, 2009				
(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					
Electricity		235	440	(136)	539
Natural gas	2	10	76	(2)	86
Fuel oil	15			(15)	
Subtotal of commodity contracts	17	245	516	(153)	625
Long-term disability plan	8				8
Nuclear decommissioning trusts					
Stocks[3]	1,772				1,772
Municipal bonds		634			634
Corporate bonds[4]		393			393
U.S. government and agency securities	240	68			308
Short-term investments, primarily cash equivalents[5]	1	14			15
Subtotal 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:					
Electricity		85	433	(73)	445
Natural gas	3	150	21	(4)	170
Subtotal of commodity contracts	3	235	454	(77)	615
Foreign currency and interest rate contracts		21			21
Total liabilities	3	256	454	(77)	636
Net assets (liabilities)	$ 3,561	$ 1,098	$ 62	$ (76)	$ 4,645

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 At December 31, 2010 and 2009, included in cash and cash equivalents and restricted cash and at December 31, 2009, also included in prepaid expenses and other on Edison International's consolidated balance sheets.

3 Approximately 67% of the equity investments were located in the United States at both December 31, 2010 and 2009.

4 Corporate bonds are diversified, and included $27 million and $50 million at December 31, 2010 and 2009, respectively, for collateralized mortgage obligations and other asset backed securities.

5 Excludes net liabilities of $5 million and net assets of $18 million at December 31, 2010 and 2009, respectively, of interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

6 Excludes $31 million and $32 million at December 31, 2010 and 2009, respectively, of cash surrender value of life insurance investments for deferred compensation.

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The following table sets forth a summary of changes in the fair value of Level 3 assets and liabilities:

	December 31,	
(in millions)	**2010**	**2009**
Fair value, net asset (liability) at beginning of period	$ 62	$ (302)
Total realized/unrealized gains (losses):		
Included in earnings[1]	64	7
Included in regulatory assets and liabilities[2]	58	312
Included in accumulated other comprehensive income	2	3
Purchases and settlements, net[3]	(100)	27
Transfers in or out of Level 3	11	15
Fair value, net asset (liability) at end of period	$ 97	$ 62
Change during the period in unrealized gains (losses) related to assets and liabilities held at the end of the period[4]	$ 143	$ 449

1 Reported in "Competitive power generation" revenue on Edison International's consolidated statements of income.

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

3 Includes EMG's impact of load requirements services contracts settled when offsetting purchases of energy derivative contracts were classified as Level 2.

4 Amounts reported in "Competitive power generation" revenue on Edison International's consolidated statements of income were $13 million and $64 million for the years ended December 31, 2010 and 2009, respectively. The remainder of the unrealized gains relate to SCE. See 2 above.

Edison International determines the fair value for transfers in and transfers out of each level at the end of each reporting period. There were no significant transfers between levels during 2010 and 2009.

Valuation Techniques Used to Determine Fair Value

Level 1

Includes assets and liabilities where fair value is determined using unadjusted quoted prices in active markets that are available at the measurement date for identical assets and liabilities. Financial assets and liabilities classified as Level 1 include exchange-traded equity securities, exchange traded derivatives, U.S. treasury securities and money market funds.

Level 2

Pricing inputs include quoted prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the derivative instrument. Financial assets and liabilities utilizing Level 2 inputs include fixed-income securities and over-the-counter derivatives.

Derivative contracts that are over-the-counter traded are valued using pricing models to determine the net present value of estimated future cash flows and are generally classified as Level 2. Inputs to the pricing models include forward published or posted clearing prices from exchanges (New York Mercantile Exchange and Intercontinental Exchange) for similar instruments and discount rates. A primary source that best represents traded activity for each market is used 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 believed to provide the most liquid market for the commodity. Broker quotes are incorporated when corroborated with other information which may include a combination of prices from exchanges, other brokers and comparison to executed trades.

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Level 3

Includes financial asset and liabilities where fair value is determined using techniques that require significant unobservable inputs. Over-the-counter options, bilateral contracts, capacity contracts, QF contracts, derivative contracts that trade infrequently (such as congestion revenue rights ("CRRs") in the California market and over-the-counter derivatives at illiquid locations), long-term power agreements, and derivative contracts with counterparties that have significant nonperformance risks are generally valued using pricing models that incorporate unobservable inputs and are classified as Level 3. Assumptions are made in order to value derivative contracts in which observable inputs are not available. 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.

For derivative contracts that trade infrequently (illiquid financial transmission rights and CRRs), changes in fair value are based on models forecasting the value of those contracts. The models, inputs are reviewed and the fair value is adjusted when it is concluded that a change in inputs would result in a new valuation that better reflects the fair value of those derivative contracts. For illiquid long-term power agreements, fair value is based upon the 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. The fair value of the majority of SCE's derivatives that are classified as Level 3 is determined using uncorroborated non-binding broker quotes 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.

Nonperformance Risk

The fair value of the derivative assets and liabilities are adjusted for nonperformance risk. To assess nonperformance risks, SCE considers the probability of and the estimated loss incurred if a party to the transaction were to default. SCE also considers collateral, netting arrangements, guarantees and other forms of credit support when assessing nonperformance. EMG 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 nonperformance risk adjustment represented an insignificant amount at both December 31, 2010 and 2009.

Nuclear Decommissioning Trusts

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.

Fair Value of Long-Term Debt Recorded at Carrying Value

The carrying amounts and fair values of long-term debt are:

	December 31,			
	2010		**2009**	
(in millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 12,419	$ 12,360	$ 10,814	$ 10,452

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Fair values of long-term debt 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 of new issue prices and relevant credit information.

The carrying value of trade receivables, payables and short-term debt approximates fair value and therefore are not included in the table above.

Note 5. Debt and Credit Agreements

Long-Term Debt

The following table summarizes long-term debt (rates and terms are as of December 31, 2010):

	December 31,	
(in millions)	**2010**	**2009**
First and refunding mortgage bonds:		
2014 2040 (4.15% to 6.05%)	$ 6,475	$ 5,475
Pollution-control bonds:		
2015 2035 (2.88% to 5.55%)	1,196	1,196
Bonds repurchased	(324)	(468)
Debentures and notes:		
2013 2053 (3.75% to 7.75%)	4,410	4,365
Wind project financings:		
Big Sky Wind, LLC		
Vendor financing loan due 2014 (LIBOR plus 2.5%)	190	
Viento Funding II, Inc.		
Term Loan due 2016 (LIBOR plus 3.875%)	150	178
Cedro Hill Wind, LLC		
Term Loan due 2025 (LIBOR plus 3.0%)	135	
Other wind project financings	98	27
Other long-term debt	117	61
Long-term debt due within one year	(48)	(377)
Unamortized debt discount net	(28)	(20)
Total	$ 12,371	$ 10,437

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. In 2010, SCE reissued $144 million of these bonds and continues to hold the remaining $75 million of these bonds which remain outstanding and have not been retired or cancelled.

Long-term debt maturities for the next five years are: 2011 $48 million; 2012 $58 million; 2013 $566 million; 2014 $1.4 billion; and 2015 $378 million.

Liens and Security Interests

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 has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2010, SCE was in compliance with this debt covenant.

In connection with Midwest Generation's financing activities, a first priority security interest was provided in substantially all the coal-fired generating plants owned by Midwest Generation and the assets relating to those plants, the receivables of EMMT directly related to Midwest Generation's hedging activities and the pledge of the intercompany notes from EME (approximately $1.3 billion at December 31, 2010). The net book value of assets pledged or mortgaged was $2.9 billion at December 31, 2010. In addition to these assets, Midwest Generation's membership interest and the capital stock of Edison Mission Midwest were pledged.

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In connection with the Viento Funding II wind financing, Viento Funding II's payment obligations are secured by pledges of its direct and indirect ownership interests in the Wildorado, San Juan Mesa and Elkhorn Ridge wind projects. In connection with the Big Sky turbine financing, the loan is secured by a leasehold mortgage on the project's real property assets, a pledge of all other collateral of the Big Sky wind project, as well as a cash reserve account into which one-third of distributable cash flow, if any, of the Big Sky wind project is to be deposited on a monthly basis. In connection with each of the High Lonesome, Laredo Ridge and Cedro Hill wind financings, the payment obligations are secured by a mortgage on the respective project's real property assets and a pledge of the respective project's material contracts. In connection with the High Lonesome financing, a security interest was also provided in an operations and maintenance reserve account and a debt service reserve account that the project is required to fund over a period of time.

For further details regarding consolidated assets pledged as security for debt obligations, see Note 3 Variable Interest Entities.

EMG Senior Notes

EMG has $3.7 billion of senior notes due 2013 through 2027. The senior notes are redeemable by EMG at any time at a price equal to 100% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, of the senior notes plus a "make-whole" premium. The senior notes are EMG's senior unsecured obligations, ranking equal in right of payment to all of EMG's existing and future senior unsecured indebtedness, and will be senior to all of EMG's future subordinated indebtedness. EMG'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 EMG's subsidiaries have guaranteed the senior notes and, as a result, all the existing and future liabilities of EMG's subsidiaries are effectively senior to the senior notes.

Project Financings

EMG completed through subsidiaries, financings of its interest in two wind projects, classified as short-term debt. The financings are required to be converted to 15-year amortizing term loans during 2011, subject to meeting specified conditions. As of December 31, 2010 there was $96 million outstanding under these financings at weighted-average interest rates that ranged from 2.76% to 3.01%.

Credit Agreements

Edison International (parent) has a $1.4 billion revolving credit facility with various banks that terminates in February 2013, with four one-year options to extend by mutual consent. Edison International's (parent) short-term debt is generally used for liquidity purposes. At December 31, 2010, the outstanding short-term debt was $19 million at a weighted-average interest rate of 0.63%. At December 31, 2009, the outstanding short-term debt was $85 million at a weighted-average interest rate of 0.60%.

SCE has two revolving credit facilities with various banks; a $2.4 billion five-year credit facility that terminates in February 2013, with four one-year options to extend by mutual consent, and a $500 million three-year credit facility that terminates in March 2013. Borrowings under these credit facilities are generally used to finance fuel inventories, balancing accounts undercollections and general, temporary cash requirements including power purchase payments. At December 31, 2010, letters of credit issued under SCE's credit facilities are scheduled to expire in twelve months or less.

EMG's subsidiaries, EME and Midwest Generation, have credit facilities of $564 million and $500 million, respectively, that both mature in June 2012. At December 31, 2010, EMG had no borrowings outstanding and $83 million of letters of credit outstanding under these credit facilities.

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The following table summarizes the status of the credit facilities at December 31, 2010:

(in millions)	SCE	EMG	Edison International (parent)
Commitment	$ 2,894	$ 1,064	$ 1,426
Outstanding borrowings			(19)
Outstanding letters of credit	(24)	(83)	
Amount available	$ 2,870	$ 981	$ 1,407

Letters of Credit

As of December 31, 2010, standby letters of credit under EME's credit facility aggregated $80 million and were scheduled to expire as follows: $72 million in 2011 and $8 million in 2012. In addition, letters of credit under EME's subsidiaries' credit facilities aggregated $36 million, $3 million of which was under Midwest Generation's credit facility, and were scheduled to expire as follows: $23 million in 2011, $3 million in 2012 and $10 million in 2017. Certain letters of credit are subject to automatic annual renewal provisions.

Note 6. Derivative Instruments and Hedging Activities

Electric Utility

SCE uses derivative financial instruments to manage exposure to commodity price risk. SCE manages these risks in part by entering into 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. As part of this program, SCE enters into energy options, swaps, forward arrangements, tolling arrangements and CRRs. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. SCE recovers its related hedging costs through the ERRA balancing account, and as a result, exposure to commodity price risk is not expected to impact earnings, but may impact cash flows.

SCE's electricity price exposure arises from energy produced and sold in CAISO's 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.

A portion 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 the Mountainview power plant 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.

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Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging activities:

		Economic Hedges	
		December 31,	
Commodity	Unit of Measure	2010	2009
Electricity options, swaps and forward arrangements	GWh	32,138	14,868
Natural gas options, swaps and forward arrangements	Bcf	250	266
Congestion revenue rights	GWh	181,291	195,367
Tolling arrangements[1]	GWh	114,599	116,398

1 In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced power purchase agreements with different project developers who have agreed to construct new southern California generating resources. SCE has entered into a number of contracts which 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 variable 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.

Fair Value of Derivative Instruments

The following table summarizes the gross and net fair values of commodity derivative instruments at December 31, 2010:

	Derivative Assets			Derivative Liabilities			
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	Net Liability
Non-trading activities							
Economic hedges	$ 87	$ 367	$ 454	$ 216	$ 449	$ 665	$ 211
Netting and collateral				(4)		(4)	(4)
Total	$ 87	$ 367	$ 454	$ 212	$ 449	$ 661	$ 207

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

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased-power expense and expects to recover these costs from ratepayers. As a result, realized gains and losses are not reflected in earnings, but may temporarily affect cash flows. Due to expected future recovery from ratepayers, unrealized gains and losses are recorded as regulatory assets and liabilities and therefore are also not reflected in 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.

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The following table summarizes the components of economic hedging activity:

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Realized gains/(losses)	$ (156)	$ (344)	$ (60)
Unrealized gains/(losses)	36	470	(638)

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 was $67 million and $91 million as of December 31, 2010 and 2009, respectively, for which SCE has posted $4 million of collateral to its counterparties. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2010, SCE would be required to post an additional $2 million of collateral.

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. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary.

Competitive Power Generation

EMG uses derivative instruments to reduce EMG's exposure to market risks that arise from price fluctuations of electricity, capacity, fuel, emission allowances, and transmission rights. Additionally, EMG's financial results can be affected by fluctuations in interest rates. The derivative financial instruments vary in duration, ranging from a few days to several years, depending upon the instrument. To the extent that EMG 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.

Risk management positions may be designated as cash flow hedges or economic hedges, which are derivatives that are not designated as cash flow hedges. Economic hedges are accounted for at fair value on EMG's consolidated balance sheets with offsetting changes recorded on the consolidated statements of income. For derivative instruments that qualify for hedge accounting treatment, the fair value is recognized, to the extent effective, on EMG's consolidated balance sheets with offsetting changes in fair value recognized in accumulated other comprehensive income until the related forecasted transaction occurs.

Derivative instruments that are utilized for trading purposes are measured at fair value and included on the consolidated balance sheets as derivative assets or liabilities. Changes in fair value are recognized in operating revenues on the consolidated statements of income.

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Where EMG's derivative instruments are subject to a master netting agreement and the criteria of authoritative guidance are met, EMG presents its derivative assets and liabilities on a net basis on its consolidated balance sheets.

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging and trading activities:

December 31, 2010

				Hedging Activities		
Commodity	**Instrument**	**Classification**	**Unit of Measure**	**Cash Flow Hedges**	**Economic Hedges**	**Trading Activities**
Electricity	Forwards/Futures	Sales	GWh	16,799[2]	22,456[4]	34,630
Electricity	Forwards/Futures	Purchases	GWh	408[2]	22,931[4]	37,669
Electricity	Capacity	Sales	MW-Day (in thousands)	190[3]		136[3]
Electricity	Capacity	Purchases	MW-Day (in thousands)	8[3]		419[3]
Electricity	Congestion	Sales	GWh		136[5]	12,020[5]
Electricity	Congestion	Purchases	GWh		1,143[5]	187,689[5]
Natural gas	Forwards/Futures	Sales	bcf[1]			30.6
Natural gas	Forwards/Futures	Purchases	bcf			34.3
Fuel oil	Forwards/Futures	Sales	barrels		250,000	10,000
Fuel oil	Forwards/Futures	Purchases	barrels		490,000	10,000
Coal	Forwards/Futures	Sales	tons			2,630,500
Coal	Forwards/Futures	Purchases	tons			2,645,500

(in millions)

Instrument	**Purpose**	**Type of Hedge**	**Notional Amount**	**Expiration Date**
Amortizing interest rate swap	Convert floating rate (6-month LIBOR) debt to fixed rate (3.175%) debt	Cash flow	$ 138	June 2016
Amortizing forward starting interest rate swap	Convert floating rate (3-month LIBOR) debt to fixed rate (4.29%) debt	Cash flow	122	December 2025
Amortizing forward starting interest rate swap	Convert floating rate (3-month LIBOR) debt to fixed rate (3.46%) debt	Cash flow	68	March 2026

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December 31, 2009

Commodity	Instrument	Classification	Unit of Measure	Hedging Activities: Cash Flow Hedges	Hedging Activities: Economic Hedges	Trading Activities
Electricity	Forwards/Futures	Sales	GWh[1]	24,355[2]	26,838[4]	23,306
Electricity	Forwards/Futures	Purchases	GWh	106[2]	25,971[4]	23,404
Electricity	Capacity	Sales	MW-Day (in thousands)	254[3]	1[3]	597[3]
Electricity	Capacity	Purchases	MW-Day (in thousands)	11[3]	2[3]	736[3]
Electricity	Congestion	Sales	GWh		136[5]	10,212[5]
Electricity	Congestion	Purchases	GWh		1,576[5]	181,930[5]
Natural gas	Forwards/Futures	Sales	bcf[1]		3.3	30.8
Natural gas	Forwards/Futures	Purchases	bcf			30.6
Fuel oil	Forwards/Futures	Sales	barrels		250,000	120,000
Fuel oil	Forwards/Futures	Purchases	barrels		625,000	120,000

(in millions)

Instrument	Purpose	Type of Hedge	Notional Amount	Expiration Date
Amortizing interest rate swap	Convert floating rate (6-month LIBOR) debt to fixed rate (3.175%) debt	Cash flow	$ 160	June 2016

1 The terms gigawatt-hours and billion cubic feet are referred to as GWh and bcf, respectively.

2 EMG's hedge products include forward and futures contracts that qualify for hedge accounting. This category excludes power contracts for the coal plants which meet the normal purchases and sales exception and are accounted for on the accrual method.

3 EMG's hedge transactions for capacity result from bilateral trades. Capacity sold in the PJM Reliability Pricing Model ("RPM") auction is not accounted for as a derivative.

4 EMG 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.

5 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.

Included in trading activities in the preceding table, EMG shows net the volume of energy trading activities that are physically settled. Gross purchases and sales totaled 3,944 GWh, 3,791 GWh and 4,080 GWh during 2010, 2009 and 2008, respectively.

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Fair Value of Derivative Instruments

The following table summarizes the fair value of derivative instruments reflected on EMG's consolidated balance sheets:

December 31, 2010

	Derivative Assets			Derivative Liabilities			
(in millions)	**Short-term**	**Long-term**	**Subtotal**	**Short-term**	**Long-term**	**Subtotal**	**Net Assets**
Non-trading activities							
Cash flow hedges	$ 54	$ 2	$ 56	$ 10	$ 25	$ 35	$ 21
Economic hedges	77	2	79	71		71	8
Trading activities	184	103	287	148	29	177	110
	315	107	422	229	54	283	139
Netting and collateral received[1]	(269)	(37)	(306)	(223)	(35)	(258)	(48)
Total	$ 46	$ 70	$ 116	$ 6	$ 19	$ 25	$ 91

December 31, 2009

	Derivative Assets			Derivative Liabilities			
(in millions)	**Short-term**	**Long-term**	**Subtotal**	**Short-term**	**Long-term**	**Subtotal**	**Net 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[1]	(479)	(55)	(534)	(426)	(32)	(458)	(76)
Total	$ 197	$ 81	$ 278	$ 5	$ 15	$ 20	$ 258

1

Netting of derivative receivables and derivative payables and the related cash collateral received and paid is permitted when a legally enforceable master netting agreement exists with a derivative counterparty.

Income Statement Impact of Derivative Instruments

The following table provides the activity of accumulated other comprehensive income, containing information about the changes in the fair value of cash flow hedges, to the extent effective, and reclassification from accumulated other comprehensive income into results of operations:

	Cash Flow Hedge Activity[1]		
(in millions)	**2010**	**2009**	**Income Statement Location**
Accumulated other comprehensive income derivative gain at January 1	$ 175	$ 398	
Effective portion of changes in fair value	92	79	
Reclassification from accumulated other comprehensive income to net income	(240)	(302)	Operating revenues
Accumulated other comprehensive income derivative gain at December 31	$ 27	$ 175	

1 Unrealized derivative gains are before income taxes. The after-tax amounts recorded in accumulated other comprehensive income at December 31, 2010 and 2009 were $16 million and $105 million, respectively.

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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.

EMG recorded net gains (losses) of $(4) million, $24 million and $7 million in 2010, 2009 and 2008, respectively, in operating revenues on the consolidated statements of income representing the amount of cash flow hedge ineffectiveness.

The effect of realized and unrealized gains (losses) from derivative instruments used for economic hedging and trading purposes on the consolidated statements of income is presented below:

		December 31,	
(in millions)	**Income Statement Location**	**2010**	**2009**
Economic hedges	Operating revenues	$ 8	$ 34
	Fuel costs	2	18
Trading activities	Operating revenues	114	47

Energy Trading Derivative Instruments

The fair value of outstanding energy trading derivative instruments at December 31, 2010 and 2009 was $110 million and $122 million, respectively. The change in the fair value of trading contracts was as follows:

	Years ended December 31,	
(in millions)	**2010**	**2009**
Fair value of trading contracts at beginning of year	$ 122	$ 112
Net gains from energy trading activities	114	47
Amount realized from energy trading activities	(131)	(44)
Other changes in fair value	5	7
Fair value of trading contracts at end of year	$ 110	$ 122

Contingent Features

Certain derivative instruments contain margin and collateral deposit requirements. Since EMG's credit ratings are below investment grade, EMG has provided collateral in the form of cash and letters of credit for the benefit of derivative counterparties. 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 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 at December 31, 2010 and, accordingly, the contingent features described above do not currently have liquidity exposure. Future increases in power prices could expose EME, Midwest Generation or EMMT to termination payments or additional collateral postings under the contingent features described above.

Commodity Price Risk Management

EMG'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 EMG's risk management policies. EMG 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 coal plants and the merchant wind projects, and uses "value at risk" metrics to help identify, measure, monitor and control its overall risk exposure in 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, EMG 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. When appropriate, EMG manages the spread between the electric prices and fuel prices, and uses forward contracts, swaps, futures, or options contracts to achieve those objectives.

Interest Rate Risk Management

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

Credit Risk

In conducting EMG's hedging and trading activities, EMG 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, EMG 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 EMG. Further, EMG 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, EMG evaluates the risk of potential defaults by counterparties. Credit risk is measured as the loss that EMG would expect to incur if a counterparty failed to perform pursuant to the terms of its contractual obligations. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary.

The majority of EMG'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.

The majority of the coal for the coal plants is purchased from suppliers under contracts which may be for multiple years. None of the coal suppliers to the coal plants have investment grade credit ratings and, accordingly, EMG may have limited recourse to collect damages in the event of default by a supplier.

The coal plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transacting in capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 66%, 48% and 50% of EMG's consolidated operating revenues for the years ended December 31, 2010, 2009 and 2008, respectively. Moody's Investors Service, Inc. ("Moody's") rates PJM's debt Aa3. PJM, a regional transmission organization ("RTO") 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, 2010 and 2009, EMG's account receivable due from PJM was $64 million and $50 million, respectively.

For the years ended December 31, 2010, 2009 and 2008, a second customer, Constellation Energy Commodities Group, Inc., accounted for less than 10%, 16% and 10%, respectively, of EMG's consolidated operating revenues. Sales to Constellation are primarily generated from the coal plants and consist of energy sales under forward contracts. The contract with Constellation is guaranteed by Constellation Energy Group, Inc., which has a senior unsecured debt rating of BBB- by Standard & Poor's Ratings Services ("S&P") and Baa3 by Moody's. At December 31, 2010 and 2009, EMG's account receivable due from Constellation was $32 million and $36 million, respectively.

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For the year ended December 31, 2008, EMG also derived 12% of its consolidated operating revenues from the sale of energy, capacity and ancillary services generated at the Midwest Generation plants to Commonwealth Edison Company under load requirements services contracts.

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers and cash received from counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the related positions. Edison International nets counterparty receivables and payables where balances exist under master netting arrangements. Edison International presents the portion of its margin and collateral deposits netted with its derivative positions on its consolidated balance sheets. The following table summarizes margin and collateral deposits provided to and received from counterparties:

	December 31,	
(in millions)	**2010**	**2009**
Collateral provided to counterparties:		
Offset against derivative liabilities	$ 8	$ 49
Reflected in margin and collateral deposits	65	125
Collateral received from counterparties:		
Offset against derivative assets	52	124
Reflected in other current liabilities	60	59

Note 7. Income Taxes

Current and Deferred Taxes

The sources of income (loss) before income taxes are:

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Domestic	$ 1,657	$ 854	$ 1,942
Foreign			2
Income from continuing operations before income taxes	1,657	854	1,944
Discontinued operations before income taxes	13	(7)	5
Income before income tax	$ 1,670	$ 847	$ 1,949

The components of income tax expense (benefit) by location of taxing jurisdiction are:

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Current:			
Federal	$ (432)	$ 1,211	$ 183
State	(86)	361	80
	(518)	1,572	263

Deferred:			
Federal	892	(1,638)	307
State	(20)	(32)	26
	872	(1,670)	333
Total continuing operations	354	(98)	596
Discontinued operations	9	(2)	5
Total	$ 363	$ (100)	$ 601

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The components of net accumulated deferred income tax liability are:

(in millions)	December 31, 2010	2009
Deferred tax assets:		
Property and software related	$ 655	$ 692
Unrealized gains and losses	400	322
Credit carryforwards	97	
Regulatory balancing accounts	230	229
Pension and PBOPs	183	216
Other	890	844
Total	2,455	2,303
Deferred tax liabilities:		
Property-related	6,637	5,285
Leveraged leases	177	194
Capitalized software costs	293	286
Regulatory balancing accounts	293	257
Unrealized gains and losses	389	315
Other	315	297
Total	8,104	6,634
Accumulated deferred income tax liability net	$ 5,649	$ 4,331
Classification of accumulated deferred income taxes net:		
Included in deferred credits and other liabilities	$ 5,625	$ 4,334
Included in current assets	$	$ 3
Included in current liabilities	$ 24	$

Effective Tax Rate

The table below provides a reconciliation of income tax expense computed at the federal statutory income tax rate to the income tax provision from continuing operations.

(in millions)	Years ended December 31, 2010	2009	2008
Income from continuing operations before income taxes	$ 1,657	$ 854	$ 1,944
Net income attributable to noncontrolling interests in the Big 4 projects		(48)	(82)
Adjusted income from continuing operations before income taxes	$ 1,657	$ 806	$ 1,862
Provision for income tax at federal statutory rate of 35%	$ 580	$ 282	$ 652
Increase (decrease) in income tax from:			
Items presented with related state income tax, net			
Global settlement related	(175)	(318)	
Change in tax accounting method for asset removal costs[1]	(40)		
State tax net of federal benefit	60	48	75
Health care legislation[2]	39		
Production and housing credits	(66)	(63)	(56)

Property-related and other	(44)	(47)	(75)
Total income tax expense from continuing operations	$ 354	$ (98)	$ 596
Effective tax rate	21.4%	(12.2)%	32.0%

1 During the second quarter of 2010, the IRS approved Edison International's request to change its tax accounting method for asset removal costs primarily related to SCE's infrastructure replacement program. As a result, Edison International recognized a $40 million earnings benefit (of which $28 million relates to asset removal costs incurred prior to 2010) from deducting asset removal costs earlier in the construction cycle. These deductions are recorded on a flow-through basis.

2 During the first quarter of 2010, Edison International recorded a $39 million non-cash charge to reverse previously recognized federal tax benefits eliminated by the federal health care legislation enacted in March 2010. The Patient Protection and Affordable Care Act, as modified by the Health Care and Education Reconciliation Act, includes a provision that eliminates the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies. Although this change does not take effect until January 1, 2013, Edison International is required to recognize the full accounting impact of the legislation in its financial statements in the period of enactment.

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The CPUC requires flow-through ratemaking 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.

Global Settlement

Edison International and the IRS finalized the terms of a Global Settlement on May 5, 2009. 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 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. The Global Settlement and termination of the Edison Capital cross-border leases resulted in a consolidated after-tax earnings charge of $254 million recorded in 2009. During 2010, Edison International recorded a $175 million earnings benefit from the acceptance by the California Franchise Tax Board of the IRS tax positions finalized in 2009 and a revision to interest recorded for the federal Global Settlement. The net cash impacts of the Global Settlement, including the state tax impact, and the termination of the Edison Capital cross border leases were payments of $373 million and receipts of approximately $1 billion in 2010 and 2009, 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.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits:

(in millions)	**2010**	**2009**	**2008**
Balance at January 1	$ 664	$ 2,237	$ 2,114
Tax positions taken during the current year:			
Increases	42	102	118
Tax positions taken during a prior year:			
Increases	273	201	162
Decreases	(332)	(224)	(157)
Decreases for settlements during the period	(82)	(1,652)	
Balance at December 31	$ 565	$ 664	$ 2,237

Unrecognized tax benefits were reduced by $82 million during 2010 related to the California Franchise Tax Board's acceptance of the federal Global Settlement as discussed above, and $1.7 billion during 2009 primarily due to completion of the federal Global Settlement as discussed above.

Edison International's federal income tax returns and its California combined franchise tax returns are currently open for years subsequent to 2002. In addition, specific California refund claims made by Edison International for years 1991 through 2002 remain subject to audit. The IRS examination phase of tax years 2003 through 2006 was completed in the fourth quarter of 2010, which included proposed adjustments for the following two items:

- A proposed adjustment increasing the taxable gain on the 2004 sale of EMG's international assets, which if sustained, would result in a federal tax payment of approximately $175 million, including interest and penalties (the IRS has asserted a 40% penalty for understatement of tax liability related to this matter).

- A proposed adjustment to disallow a component SCE's repair allowance deduction, which if sustained, would result in a federal tax payment of approximately $90 million, including interest.

Edison International disagrees with the proposed adjustments and filed a protest with the IRS on January 28, 2011.

During the fourth quarter of 2010, Edison International made a tax and interest deposit of $166 million primarily related to rollforward issues included in the Global Settlement that subsequently impacted tax years 2003 through 2006.

As of December 31, 2010, Edison International had $97 million of federal tax credit carryforwards with expiration dates beginning in 2029.

As of December 31, 2010 and 2009, respectively, if recognized, $455 million and $374 million of the unrecognized tax benefits would impact the effective tax rate.

Accrued Interest and Penalties

The total amount of accrued interest and penalties related to Edison International's income tax liabilities was $188 million and $380 million as of December 31, 2010 and 2009, respectively.

The net after-tax interest and penalties recognized in income tax expense was a benefit of $153 million and $80 million in 2010 and 2009, respectively, compared to an expense of $23 million in 2008.

Note 8. 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 $80 million in 2010, $83 million in 2009 and $80 million in 2008.

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 $127 million for the year ending December 31, 2011. Annual contributions made to most of SCE's pension plans are recovered through CPUC-approved regulatory mechanisms. Annual contributions to these plans are expected to be, at a minimum, equal to the related annual expense.

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 and 2010 partially offset the impacts of the 2008 market conditions.

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Changes in the plan's funded status also affect the assets and liabilities recorded on Edison International's 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 established new minimum funding standards and placed various restrictions on underfunded plans.

Information on plan assets and benefit obligations is shown below:

	Years ended December 31,	
(in millions)	**2010**	**2009**
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 3,688	$ 3,439
Service cost	149	124
Interest cost	210	207
Amendments	6	21
Actuarial loss	210	80
Benefits paid	(183)	(183)
Projected benefit obligation at end of year	$ 4,080	$ 3,688
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,857	$ 2,340
Actual return on plan assets	434	577
Employer contributions	127	123
Benefits paid	(183)	(183)
Fair value of plan assets at end of year	$ 3,235	$ 2,857
Funded status at end of year	$ (845)	$ (831)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$ (12)	$ (10)
Long-term liabilities	(833)	(821)
	$ (845)	$ (831)
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	$ 1	$ 2
Net loss	116	96
	$ 117	$ 98
Amounts recognized as a regulatory asset:		
Prior service cost	$ 40	$ 42
Net loss	500	556
	$ 540	$ 598
Total not yet recognized as expense	$ 657	$ 696
Accumulated benefit obligation at end of year	$ 3,736	$ 3,342
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 4,080	$ 3,688
Accumulated benefit obligation	3,736	3,342
Fair value of plan assets	3,235	2,857

Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	5.25%	6.0%
Rate of compensation increase	5.0%	5.0%

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Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years ended December 31, 2010	2009	2008
Service cost	$ 149	$ 124	$ 120
Interest cost	210	207	199
Expected return on plan assets	(210)	(169)	(259)
Amortization of prior service cost	8	11	17
Amortization of net loss	22	61	5
Expense under accounting standards	179	234	82
Regulatory adjustment deferred	(52)	(94)	(4)
Total expense recognized	$ 127	$ 140	$ 78

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

(in millions)	Years ended December 31, 2010	2009	2008
Net loss	$ 30	$ 17	$ 59
Amortization of prior service cost	(1)	(1)	(1)
Amortization of net loss	(10)	(11)	(5)
Total recognized in other comprehensive income	$ 19	$ 5	$ 53
Total recognized in expense and other comprehensive income	$ 146	$ 145	$ 131

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 2011 are $24 million and $7 million, respectively; $13 million of the net loss is expected to be reclassified from accumulated other comprehensive loss.

The following are weighted-average assumptions used to determine expense:

	Years ended December 31, 2010	2009	2008
Discount rate	6.0%	6.25%	6.25%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected long-term return on plan assets	7.5%	7.5%	7.5%

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

(in millions)	Years ended December 31,
2011	$ 277

2012	288
2013	297
2014	307
2015	320
2016 2020	1,691

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

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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 $56 million for the year ending December 31, 2011. Annual contributions made to SCE plans are recovered through CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to the total annual expense for these plans.

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 market conditions in 2009 and 2010 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 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 this trust.

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Information on plan assets and benefit obligations is shown below:

	Years ended December 31,	
(in millions)	**2010**	**2009**
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,110	$ 2,351
Service cost	37	30
Interest cost	127	122
Amendments	23	(65)
Actuarial loss (gain)	216	(242)
Plan participants' contributions	17	15
Medicare Part D subsidy received	5	5
Benefits paid	(110)	(106)
Benefit obligation at end of year	$ 2,425	$ 2,110
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,459	$ 1,212
Actual return on assets	175	257
Employer contributions	60	76
Plan participants' contributions	17	15
Medicare Part D subsidy received	5	5
Benefits paid	(110)	(106)
Fair value of plan assets at end of year	$ 1,606	$ 1,459
Funded status at end of year	$ (819)	$ (651)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$ (20)	$ (18)
Long-term liabilities	(799)	(633)
	$ (819)	$ (651)
Amounts recognized in accumulated other comprehensive loss (income) consist of:		
Prior service cost (credit)	$ 7	$ (5)
Net loss	28	15
	$ 35	$ 10
Amounts recognized as a regulatory asset (liability):		
Prior service credit	$ (161)	$ (209)
Net loss	718	625
	$ 557	$ 416
Total not yet recognized as expense	$ 592	$ 426
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	5.5%	6.0%
Assumed health care cost trend rates:		
Rate assumed for following year	9.75%	8.25%
Ultimate rate	5.5%	5.5%
Year ultimate rate reached	2019	2016

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Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	2010	2009	2008
	Years ended December 31,		
Service cost	$ 37	$ 30	$ 41
Interest cost	127	122	136
Expected return on plan assets	(101)	(81)	(123)
Amortization of prior service credit	(38)	(34)	(31)
Amortization of net loss	36	45	16
Total expense	$ 61	$ 82	$ 39

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

(in millions)	2010	2009	2008
	Years ended December 31,		
Net loss (gain)	$ 13	$ (8)	$ 6
Prior service cost (credit)	11	(3)	3
Amortization of prior service credit	2	2	2
Amortization of net loss	(1)	(1)	(2)
Total recognized in other comprehensive income	$ 25	$ (10)	$ 9
Total recognized in expense and other comprehensive income	$ 86	$ 72	$ 48

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 2011 are $38 million and $(37) million, respectively, including $2 million and $(1) million, respectively, expected to be reclassified from accumulated other comprehensive loss.

The following are weighted-average assumptions used to determine expense:

	2010	2009	2008
	Years ended December 31,		
Discount rate	6.0%	6.25%	6.25%
Expected long-term return on plan assets	7.0%	7.0%	7.0%
Assumed health care cost trend rates:			
Current year	8.25%	8.75%	9.25%
Ultimate rate	5.5%	5.5%	5.0%
Year ultimate rate reached	2016	2016	2015

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2010 by $284 million and annual aggregate service and interest costs by $17 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2010 by $237 million and annual aggregate service and interest costs by $14 million.

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The following benefit payments are expected to be paid:

	Year ending December 31,	
(in millions)	**Before Subsidy***	**Net**
2011	$ 96	$ 91
2012	112	106
2013	122	115
2014	131	123
2015	139	131
2016 2020	837	782

* 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. Target allocations for pension plan assets are 30% for U.S. equities, 16% for non-U.S. equities, 35% for fixed income, 15% for opportunistic and/or alternative investments and 4% for other investments. Target allocations for PBOP plan assets are 41% for U.S. equities, 17% for non-U.S. equities, 34% for fixed income, 7% for opportunistic and/or alternative investments, and 1% for other investments. 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 investment 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.

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.

Opportunistic, Alternative and Other Investments:

Opportunistic: Investments in short to intermediate term market opportunities. Investments may have fixed income and/or equity characteristics and may be either liquid or illiquid.

Alternative: Limited partnerships that invest in non-publicly traded entities.

Other: Investments diversified among multiple asset classes such as global equity, fixed income currency and commodities markets. Investments are made in liquid instruments within and across markets. The investment returns are expected to approximate the plans' expected investment returns.

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 plans' investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct

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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 securities 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. equities, non-U.S. equities and hedge funds includes a 3% premium over the estimated total return for intermediate United States government bonds. The rate of return for private equity 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 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. Futures contracts trade on an exchange and therefore are 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. The Level 1 registered investment companies are either mutual or money market funds. The remaining funds in this category are readily redeemable at NAV and classified as Level 2 and are discussed further at footnote 6 to the pension plan master trust investments table below.

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Pension Plan

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2010 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks[1]	$ 786	$	$	$ 786
Common/collective funds[2]		600		600
Corporate bonds[3]		555		555
Partnerships/joint ventures[4]		155	345	500
U.S. government and agency securities[5]	84	316		400
Registered investment companies[6]	84	169		253
Other investment entities[7]		159		159
Interest-bearing cash	5			5
Other	2	30		32
Total	$ 961	$ 1,984	$ 345	$ 3,290
Receivables and payables, net				(55)
Net plan assets available for benefits				$ 3,235

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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
Partnerships/joint ventures[4]		101	240	341
U.S. government and agency securities[5]	104	352		456
Registered investment companies[6]	73	58		131
Other investment entities[7]		135		135
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. For 2010 and 2009, respectively, performance is primarily benchmarked against the Russell Indexes (63% and 61%) and Morgan Stanley Capital International (MSCI) index (37% and 39%).

2 At December 31, 2010 and 2009, respectively, 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 (29% and 33%), Russell 200 and Russell 1000 indexes (28% and 26%) and the MSCI Europe, Australasia and Far East (EAFE) Index (11% and 10%). A non-index U.S. equity fund representing 23% and 20% of this category as of December 31, 2010 and 2009, respectively, is actively managed. Another fund representing 8% and 7% of this category as of December 31, 2010 and 2009, respectively, is a global asset allocation fund.

3 Corporate bonds are diversified. At December 31, 2010 and 2009, respectively, this category includes $65 million and $52 million for collateralized mortgage obligations and other asset backed securities of which $17 million and $12 million are below investment grade.

4 Partnerships/joint venture Level 2 investments consist primarily 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 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.

5 Level 1 U.S. government and agency securities are U.S. treasury bonds and notes. Level 2 primarily relates to the Federal National Mortgage Association and the Federal Home Loan Mortgage Corporation.

6 Level 1 of registered investment companies consists of a global equity mutual fund which seeks to outperform the MSCI World Total Return Index. Level 2 of this category primarily consists of (1) short-term, emerging market and high yield bond funds and (2) a hedge fund that invests through liquid instruments in a global diversified portfolio of equity, fixed income, interest rate, foreign currency and commodities markets.

7 At December 31, 2010 and 2009, respectively, 57% and 64% of the other investment entities balance is invested in emerging market equity securities. At December 31, 2010 and 2009, respectively, about 24% and 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.

At December 31, 2010 and 2009, approximately 69% and 67%, respectively, of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

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The following table sets forth a summary of changes in the fair value of Level 3 investments for 2010 and 2009:

(in millions)	2010	2009
Fair value, net at beginning of period	$ 240	$ 111
Actual return on plan assets:		
Relating to assets still held at end of period	42	34
Relating to assets sold during the period	24	6
Purchases and dispositions, net	39	89
Transfers in and /or out of Level 3		
Fair value, net at end of period	$ 345	$ 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, 2010 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Common/collective funds[1]	$	$ 657	$	$ 657
Corporate stocks[2]	344			344
Corporate notes and bonds[3]		184		184
Registered investment companies[4]	144	1		145
Partnerships[5]		16	92	108
U.S. government and agency securities[6]	50	38		88
Interest bearing cash	12			12
Other[7]	4	76		80
Total	$ 554	$ 972	$ 92	$ 1,618
Receivables and payables, net				(12)
Combined net plan assets available for benefits				$ 1,606

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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
Corporate notes and bonds[3]		151		151
Registered investment companies[4]	213			213
Partnerships[5]			49	49
U.S. government and agency securities[6]	39	28		67
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 61% of the common/collective assets are invested in a large cap index fund which seeks to track performance of the Russell 1000 index. 23% of the assets in this category are in index funds which seek to track performance in the MSCI 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 (65% and 67%) and the MSCI All Country World (ACWI) index (35% and 33%) for 2010 and 2009, respectively.

3 Corporate notes and bonds are diversified and include approximately $15 million and $10 million for commercial collateralized mortgage obligations and other asset backed securities at December 31, 2010 and 2009, respectively.

4 Level 1 registered investment companies consist of an investment grade corporate bond mutual fund and a money market fund.

5 At December 31, 2010 and 2009, respectively, 84% and 90% of the Level 3 partnerships category is invested in (1) asset backed securities including distressed mortgages and (2) distressed companies.

6 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.

7 Other includes $64 million and $58 million of municipal securities at December 31, 2010 and 2009, respectively.

At December 31, 2010 and 2009, approximately 67% and 76%, respectively, 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 2010 and 2009:

(in millions)	2010	2009
Fair value, net at beginning of period	$ 49	$ 12
Actual return on plan assets		
Relating to assets still held at end of period	14	12
Relating to assets sold during the period		1
Purchases and dispositions, net	29	27
Transfers in and /or out of Level 3		(3)

Fair value, net at end of period	$ 92	$ 49

Stock-Based Compensation

Edison International maintains a shareholder approved incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. The maximum number of shares of Edison International's common stock authorized to be issued or transferred pursuant to awards under the 2007 Performance Incentive Plan, as amended in 2009, is 21.5 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"). As of December 31,

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2010, Edison International had approximately 9 million shares remaining for future issuance under its stock-based compensation plans.

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, 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 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,		
	2010	**2009**	**2008**
Expected terms (in years)	7.3	7.4	7.4
Risk-free interest rate	2.0% 3.2%	2.8% 3.5%	2.6% 3.8%
Expected dividend yield	3.3% 4.0%	3.6% 5.0%	2.3% 3.9%
Weighted-average expected dividend yield	3.8%	4.9%	2.6%
Expected volatility	18.8% 19.8%	20% 21%	17% 19%
Weighted-average volatility	19.8%	20.6%	17.6%

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 87 months, 84 months and 72 months at December 31, 2010, 2009 and 2008, respectively.

The following is a summary of the status of Edison International stock options:

		Weighted-Average		
	Stock options	**Exercise Price**	**Remaining Contractual Term (Years)**	**Aggregate Intrinsic Value**
Outstanding at December 31, 2009	17,368,032	$ 32.15		
Granted	3,847,601	33.34		
Expired	(39,053)	47.21		
Forfeited	(309,427)	31.05		
Exercised	(1,724,944)	22.10		
Outstanding at December 31, 2010	19,142,209	33.28	6.22	

Vested and expected to vest at December 31, 2010	18,684,498	33.31	6.17	$ 146,201,181
Exercisable at December 31, 2010	10,602,908	33.88	4.60	$ 84,480,082

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At December 31, 2010, 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.

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2008, March 2009 and March 2010, and vest at the end of December 2010, 2011 and 2012, 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 total shareholder return relative to the total shareholder return 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 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 shares expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants.

The fair value of performance shares is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires various assumptions noted in the following table.

	Years ended December 31,		
	2010	**2009**	**2008**
Equity awards			
Grant date risk-free interest rate	1.3%	1.3%	3.9%
Grant date expected volatility	21.6%	21.4%	17.4%
Liability awards[1]			
Expected volatility	20.6%	21.9%	19.2%
Risk-free interest rate:			
2010 awards	0.6%		
2009 awards	0.3%	1.1%	
2008 awards		0.5%	0.8%

1 The portion of performance shares classified as share-based liability awards are revalued at each reporting period.

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 with terms nearest to the remaining term of the performance shares and is used as a proxy for the expected return for the specified group of peer companies. Expected volatility is based on the historical volatility of Edison International's (and the specified group of peer 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.

At December 31, 2010, there was $4 million (based on the December 31, 2010 fair value of performance shares classified as equity awards) of total unrecognized compensation cost related to performance shares.

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That cost is expected to be recognized over a weighted-average period of approximately two years. The following is a summary of the status of Edison International nonvested performance shares:

	Equity Awards		Liability Awards	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Fair Value
Nonvested at December 31, 2009	343,452	$ 35.41	343,452	
Granted	145,768	32.25	145,768	
Forfeited	(74,192)	53.93	(74,192)	
Nonvested at December 31, 2010	415,028	30.99	415,028	$ 34.74

The current portion of nonvested performance shares classified as liability awards is reflected in "Other current liabilities" and the long-term portion is reflected in "Pensions and benefits" on the consolidated balance sheets.

Restricted Stock Units

Restricted stock units were awarded to executives in March 2008, March 2009 and March 2010 and vest and become payable in January 2011, 2012 and 2013, respectively. Each restricted stock unit awarded is a contractual right to receive one share of Edison International common stock, if vesting requirements are satisfied. Restricted stock units awarded contain dividend equivalent reinvestment rights. An additional number of restricted stock units 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 restricted stock units is dependent upon continuous service through the end of the three-calendar-year-plus-two-days vesting period. Vesting is subject to a pro-rated adjustment for employees who are terminated under certain circumstances or retire. Cash awards are substituted to the extent necessary to pay tax withholding or any government levies.

The following is a summary of the status of Edison International nonvested restricted stock units granted to SCE employees:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2009	392,902	$ 32.16
Granted	281,990	32.12
Forfeited	(19,248)	32.93
Paid Out	(10,848)	33.37
Nonvested at December 31, 2010	644,796	32.18

The fair value for each restricted stock unit awarded is determined as the closing price of Edison International common stock on the grant date.

Compensation expense related to these shares, which is based on the grant-date fair value, is recognized ratably over the requisite service period, except for awards whose holders become eligible for retirement vesting during the service period, in which case recognition is accelerated into the year the holders become eligible for retirement vesting. At December 31, 2010, there was $7 million of total unrecognized compensation cost related to restricted stock units, net of expected forfeitures, which is expected to be recognized as follows: $5 million in 2011 and $2 million in 2012.

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Supplemental Data on Stock Based Compensation

(in millions, except per award amounts)	Years ended December 31, 2010	2009	2008
Stock Based Compensation Expense[1]			
Stock options	$ 18	$ 13	$ 25
Performance shares	10	5	(4)
Restricted stock units	7	5	3
Other	9	10	7
Total stock based compensation expense	$ 44	$ 33	$ 31
Income tax benefits related to stock compensation expense	$ 17	$ 13	$ 12
Excess tax benefits[2]	8	9	10
Stock options			
Weighted average grant date fair value per option granted	$ 4.89	$ 3.05	$ 9.70
Fair value of options vested	18	14	24
Cash used to purchase shares to settle options	61	25	55
Cash from participants to exercise stock options	38	13	30
Value of options exercised	23	12	24
Tax benefits from options exercised	9	5	10
Performance Shares Classified as Equity Awards			
Weighted average grant date fair value per share granted	$ 32.25	$ 21.42	$ 45.53
Fair value of shares vested	4	1	4
Value of shares settled			10
Tax benefits realized from settlement of awards			4
Performance Shares Classified as Liability Awards			
Value of shares settled	$	$	$ 12
Tax benefits realized from settlement of awards			5
Restricted Stock units[3]			
Weighted average grant date fair value per unit granted	$ 32.12	$ 25.21	$ 45.96

1 Reflected in "Operations and maintenance" on the consolidated statements of income.

2 Reflected in "Settlements of stock based compensation net" in the financing section of the consolidated statements of cash flows.

3 The value of restricted stock units settled was less than $1 million for 2010, 2009 and 2008.

Note 9. Commitments and Contingencies

Third-Party Power Purchase Agreements

SCE enters into various agreements to purchase power and electric capacity, including:

Renewable Energy Contracts California law requires retail sellers of electricity to comply with an RPS by purchasing renewable energy (such as biomass, small hydroelectric, wind, solar, and geothermal energy), so that the amount of electricity delivered from eligible renewable resources equals at least 20% of their total retail sales by the end of 2010 or such later date as is permitted by flexible compliance rules. Renewable contract payments generally consist of payments based on a fixed price per megawatt hour. As of December 31, 2010, SCE had 97 renewable energy contracts that were approved by the CPUC and met critical contract provisions which expire at various dates between 2011 and 2033.

Qualifying Facility Power Purchase Agreements Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities are required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities and qualifying small power production facilities

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("QFs"). As of December 31, 2010, SCE had 170 QF contracts which expire at various dates between 2011 and 2026.

Other Power Purchase Agreements In accordance with the SCE's CPUC-approved long-term procurement plans, SCE has entered into capacity agreements with third parties, including 14 tolling arrangements, 47 power call options and 106 resource adequacy contracts. SCE's obligations under a portion of these agreements are limited to payments for the availability of such resources.

At December 31, 2010, the undiscounted future expected payments for power purchase agreements that have been approved by the CPUC and have completed major milestones for construction were as follows:

(in millions)	Renewable Energy Contracts	QF Power Purchase Agreements	Other Purchase Agreements
2011	$ 340	$ 429	$ 548
2012	494	411	616
2013	568	411	748
2014	633	410	638
2015	634	399	468
Thereafter	11,007	1,663	3,336
Total future commitments	$ 13,676	$ 3,723	$ 6,354

Some of the power purchase agreements that SCE entered into with independent power producers are treated as operating and capital leases. The following table shows the future fixed capacity payments due under the contracts that are treated as operating and capital leases (these amounts are also included in the table above). The fixed capacity payments for capital leases are discounted to their present value in the table below using SCE's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	Operating Leases	Capital Leases
2011	$ 740	$ 33
2012	717	71
2013	761	131
2014	708	153
2015	693	154
Thereafter	8,741	2,479
Total future commitments	$ 12,360	$ 3,021
Amount representing executory costs		(628)
Amount representing interest		(1,168)
Net commitments		$ 1,225

Operating lease expense for these power purchase agreements was $350 million in 2010, $358 million in 2009 and $328 million in 2008. The timing of SCE's recognition of the lease expense conforms to 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.

At December 31, 2010 and 2009, net capital leases reflected in "Utility plant" on the consolidated balance sheets were $227 million and $235 million, including amortization of $22 million and $13 million, respectively. SCE had $5 million and $8 million included in "Other current liabilities" and $222 million and $227 million included in "Other deferred credits and other liabilities," representing the present value of the fixed capacity payments due under these contracts recorded on the consolidated balance sheets at December 31, 2010 and 2009, respectively.

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Both capital and operating leases have varying terms, provisions and expiration dates. The contingent rentals for capital leases were less than $1 million for both 2010 and 2009.

Power Plant and Other Lease Commitments

The following summarizes the estimated minimum future commitments for noncancelable power plant (which are related to EMG's long-term leases primarily related to the Illinois power facilities and Homer City facilities) and other operating leases (excluding SCE's power purchase agreements discussed above):

(in millions)	Operating Leases Power Plants	Operating Leases Other
2011	$ 312	$ 88
2012	311	84
2013	300	85
2014	289	68
2015	174	61
Thereafter	1,527	395
Total future commitments	$ 2,913	$ 781

The minimum commitments above do not include EMG'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. There were no sublease rentals.

Operating lease expense for power plants and other leases (primarily related to vehicles, office space and other equipment) were $279 million in 2010, $256 million in 2009 and $255 million in 2008.

Sale-Leaseback Transactions

On December 7, 2001, a subsidiary of EMG completed a sale-leaseback of EMG's Homer City plant to third-party lessors. Under the terms of the 33.67-year leases, EMG'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 plant, EMG has a right of first refusal to acquire the interest at fair market value. 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 EMG completed a sale-leaseback of EMG's Powerton and Joliet power facilities located in Illinois to third-party lessors. Under the terms of the leases (33.75 years for Powerton and 30 years for Joliet), EMG's subsidiary makes semi-annual lease payments on each January 2 and July 2, which began January 2, 2001. EMG guarantees its subsidiary's payments under the leases. If a lessor intends to sell its interest in the Powerton or Joliet power facility, EMG has a right of first refusal to acquire the interest at fair market value. 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 EMG's subsidiaries unless specified financial covenants are met. At December 31, 2010, EMG'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.

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 recorded liability to decommission SCE's nuclear power facilities is $2.4 billion as of December 31, 2010, based on site-specific studies performed in 2008 for San Onofre and 2007 for 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 $8.6 billion through 2053 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.8% to 6.9% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $23 million per year. Contributions received in prior years were approximately $46 million. SCE estimates annual after-tax earnings on the decommissioning funds of 4.2% to 5.7%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable 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.

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 of $63 million at December 31, 2010. Total expenditures for the decommissioning of San Onofre Unit 1 were $596 million from the beginning of the project in 1998 through December 31, 2010.

Decommissioning expense under the ratemaking method was $30 million in 2010 and $46 million in both 2009 and 2008. The ARO for decommissioning SCE's active nuclear facilities was $2.4 billion and $3.1 billion at December 31, 2010 and 2009, respectively. See Note 4 and Note 15 for discussion on the nuclear decommissioning trusts.

Other Commitments

Certain other commitments for the years 2011 through 2015 are estimated below:

(in millions)	**2011**	**2012**	**2013**	**2014**	**2015**
Fuel supply contracts	$ 742	$ 428	$ 222	$ 143	$ 166
Gas and coal transportation agreements	239	8	8	9	8
Turbine commitments	90				
Capital expenditures	182				
Other contractual obligations	90	78	38	11	10

Fuel Supply Contracts

SCE has fuel supply contracts which require payment only if 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.

At December 31, 2010, Midwest Generation and Homer City had commitments to purchase coal from third-party suppliers at fixed prices, subject to adjustment clauses. In January 2011, Midwest Generation entered into additional contractual agreements for the purchase of coal. These commitments, together with estimated transportation costs under existing agreements, total $34 million for 2011.

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 2008 reflected in "Lease terminations and other" on the consolidated statements of income.

Gas and Coal Transportation Agreements

At December 31, 2010, EMG had a contractual commitment to transport natural gas. EMG's share of the commitment to pay minimum fees under its gas transportation agreement, which has a remaining contract length of seven years, is estimated to aggregate $41 million in the next five years. EMG has entered into agreements to re-sell the transportation under this agreement which aggregates $50 million over the same period.

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At December 31, 2010, Midwest Generation and Homer City had contractual agreements for the transportation of coal. 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.

Turbine Commitments

To support its renewable program, EMG has entered into several agreements for the purchase of turbines. Under one of these agreements, EMG's failure to schedule turbine delivery by June 2011 would result in a termination obligation equal to its turbine deposit, which would result in a $21 million charge against earnings. EMG has identified a project in which to place these turbines. However, development is not complete, and EMG cannot be assured that this project will be constructed.

On October 8, 2010, an agreement was reached to settle disputes included in the complaint filed by EMG against Mitsubishi Power Systems Americas, Inc. and Mitsubishi Heavy Industries, Ltd. with respect to a wind turbine generator supply agreement. As a result of this agreement, EMG committed to purchase on amended terms 23 wind turbines (aggregating 55 MW), agreed to certain price adjustments on the turbines purchased under the original contract, may elect to deploy up to 60 additional wind turbines (aggregating 144 MW) that were part of the original contract, or may be obligated to make a payment of up to $30 million following the end of the three-year period if it has not elected to deploy the additional turbines and if certain other criteria apply. EMG made payments of $20 million in 2010 and further agreed to payments up to $20 million for settlement of remaining disputes related to turbines purchased.

Capital Expenditures

At December 31, 2010, EMG's subsidiaries had firm commitments for capital and construction expenditures primarily related to selective non-catalytic reduction (SNCR) equipment at the Midwest Generation plants and the construction of wind projects. EMG intends to fund these expenditures through project-level and turbine vendor financing, U.S. Treasury grants, cash on hand and cash generated from operations. EMG has secured $394 million in wind project financing and anticipated U.S. Treasury grants. For further discussion, see Note 5.

Other Contractual Obligations

At December 31, 2010, EMG and its subsidiaries were party to turbine operations and maintenance agreements, agreements for the purchase of materials used in the operation of environmental controls equipment and a coal cleaning agreement.

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.

Environmental Indemnities Related to the Midwest Generation Plants

In connection with the acquisition of the Midwest Generation plants, EMG agreed to indemnify Commonwealth Edison Company (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, EMG agreed to indemnify the lessors for specified environmental liabilities. Due to the nature of the obligations under these indemnities, a maximum potential liability cannot be determined. Commonwealth Edison has advised EMG 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." Except as discussed below, EMG has not recorded a liability related to these environmental indemnities.

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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 2012. There were approximately 223 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2010. While the range of this liability is between $46 million and $67 million, Midwest Generation had recorded a $56 million and $50 million liability at December 31, 2010 and 2009, respectively, for previous, pending and future claims.

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 Plant

In connection with the acquisition of the Homer City plant, 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 this obligation of Homer City. Also, in connection with the sale-leaseback transaction related to the Homer City plant, Homer City agreed to indemnify the lessors for specified environmental liabilities. Due to the nature of the obligations under these indemnity provisions, they are not subject to a maximum potential liability and do not have expiration dates. For discussion of the New Source Review lawsuit filed against Homer City, see " Contingencies Homer City New Source Review Lawsuit." EME has not recorded a liability related to this indemnity.

Indemnities Provided under Asset Sale and Sale-Leaseback 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, 2010 and 2009, EME had recorded a liability of $42 million (of which $3 million is classified as a current liability) and $96 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 assets 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. No significant amounts are recorded as a liability for these matters.

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In connection with the sale-leaseback transactions related to the Homer City plant 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. No significant amounts are recorded as a liability for these matters.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of the Mountainview power plant, 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

The 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, the groundwater 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 indemnity.

Other Edison International Indemnities

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

Midwest Generation New Source Review Lawsuit

In August 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 that Midwest Generation or Commonwealth Edison performed repair or replacement projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration ("PSD") requirement and of the New Source Performance Standards of the Clean Air Act ("CAA"), including alleged requirements to obtain a construction permit and to install controls sufficient to meet best available control technology ("BACT") emission rates. 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 also alleged violations of certain opacity and particulate matter standards at the Midwest Generation plants. 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 New Source Review ("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 the requirements of the Combined Pollutant Standard ("CPS"). Several Chicago-based environmental action groups have intervened in the case.

Nine of the ten counts related to PSD requirements in the complaint were dismissed in March 2010, and the tenth count was also dismissed to the extent it sought civil penalties under the CAA, as barred by the applicable statute of limitations. The court did not address (i) other counts in the complaint that allege violations of opacity and particulate matter limitations under the Illinois State Implementation Plan and Title V of the CAA, or (ii) the complaint in intervention filed by the Chicago-based environmental action groups, which also alleges opacity and particulate matter violations.

In June 2010, the US EPA, the State of Illinois, and several environmental action groups filed amended complaints in the New Source Review litigation. The amended complaints are similar to the prior complaints, but seek to add Commonwealth Edison and EME as defendants and introduce new legal theories to impose liability on Midwest Generation and EME. Midwest Generation, EME and Commonwealth Edison have filed a motion to dismiss the amended complaints.

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.

Homer City New Source Review Lawsuit

In January 2011, the US EPA filed a complaint in the Western District of Pennsylvania against Homer City, the sale-leaseback owner participants of the Homer City plant, and two prior owners of the Homer City plant. The complaint alleges violations of the PSD and Title V provisions of the CAA and its implementing regulations, including requirements contained in the Pennsylvania State Implementation Plan. The PSD counts allege that the prior owners of the Homer City plant performed projects in the 1990s that triggered state and federal PSD permitting requirements by increasing emissions of sulfur dioxide and/or particulate matter. All defendants are alleged to have failed to comply with the PSD permitting requirements for those projects. The complaint also alleges that, as a result of triggering PSD permitting requirements, including the requirement to install controls sufficient to meet BACT emissions for sulfur dioxide and/or particulate matter, the owners and operators have been required, but have failed, to incorporate emissions limitations that meet BACT into the station's Title V operating permit. In addition to seeking penalties ranging from $32,500 to $37,500 per violation, per day, the complaint calls for an injunction ordering Homer City 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. Pennsylvania Department of Environmental Protection ("PADEP"), the State of New York and the State of New Jersey have intervened in the lawsuit.

Also in January 2011, two residents filed a complaint in the Western District of Pennsylvania, on behalf of themselves and all others similarly situated, against Homer City, the sale-leaseback owner participants of the Homer City plant, two prior owners of the Homer City plant, EME, and Edison International, claiming that emissions from the Homer City plant had adversely affected their health and property values. The plaintiffs seek to have their suit certified as a class action and request injunctive relief, the funding of a health assessment study and medical monitoring, compensatory and punitive damages.

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

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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. As amended in April 2010, the Navajo Nation's complaint asserts claims for, among other things, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, plus interest thereon, and punitive damages of not less than $1 billion. No trial date has been set for this litigation. 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. In October 2010, the Hopi Tribe settled all of its claims and the remaining parties agreed to engage in mediation. SCE cannot predict the outcome of the Navajo Nation's complaint against SCE.

Environmental Remediation

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

As of December 31, 2010, Edison International's recorded estimated minimum liability to remediate its 29 identified material sites (sites in which the upper end of the range of costs is at least $1 million) at SCE (23 sites) and EMG (6 sites primarily related to Midwest Generation) was $53 million, of which $50 million was related to SCE, including $20 million related to San Onofre. In addition to its identified material sites SCE also has 34 immaterial sites for which the total minimum recorded liability was $4 million. 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 at these identified material sites and immaterial sites could exceed its recorded liability by up to $200 million and $7 million, respectively, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes.

The CPUC allows SCE to recover 90% of its environmental remediation costs at certain sites, representing $29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE recovers 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 $51 million for its estimated minimum environmental cleanup costs expected to be recovered through customer rates.

SCE'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 SCE 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 $3 million to $18 million. Recorded costs were

$17 million, $11 million and $29 million for the years ended December 31, 2010, 2009 and 2008, 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.

2010 FERC Rate Case

In February 2011, the FERC approved a settlement agreement in SCE's 2010 FERC rate case that provides a FERC retail base revenue requirement of $490 million, an increase of $42 million, or 9.4%, over the 2009 FERC base revenue requirement. The increased revenue requirement is primarily due to an increase in transmission capital investments and will be retroactive to March 1, 2010. As of December 31, 2010, SCE had collected revenue, subject to refund, of $58 million that will be refunded to ratepayers. SCE did not previously recognize revenue for the amount that will be refunded.

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 entities 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 $43 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the Department of Energy ("DOE") is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its 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.

In January 2004, SCE, as operating agent of San Onofre, 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. In June 2010, the United States Court of Federal Claims issued a decision granting SCE damages of approximately $142 million to recover costs incurred through December 31, 2005, which has been appealed by the DOE. Additional legal action would be necessary to recover damages incurred after that date. Any damages recovered would be returned to SCE ratepayers or used to offset past or future fuel decommissioning or storage costs for the benefit of ratepayers.

Note 10. Regulatory and Environmental Developments

Regulatory Developments

Wildfire Insurance Issues

Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. On September 1, 2010, SCE's parent, Edison International, renewed its insurance coverage, which included coverage for SCE's wildfire liabilities up to a $610 million limit (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 additional self-insured costs in the event of multiple wildfire occurrences during the policy period (September 1, 2010 to August 31, 2011). SCE may experience 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.

Environmental Developments

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 the environmental impact of past operations.

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 any additional costs arising from such developments would be recovered from customers or that Edison International's financial position, results of operations and cash flows would not be materially affected by these developments.

Midwest Generation Environmental Compliance Plans and Costs

During 2010, Midwest Generation continued its permitting and planning activities for nitrogen oxide ("NO_x") and sulfur dioxide ("SO_2") controls to meet the requirements of the CPS. Midwest Generation has received all necessary permits from the Illinois Environmental Protection Agency ("Illinois EPA") allowing the installation of SNCR technology on multiple units to meet the NO_x portion of the CPS. In November 2010 and February 2011, the Illinois EPA issued construction permits authorizing Midwest Generation to install a dry sorbent injection system using Trona or its equivalent at the Waukegan generating station's Unit 7 and Units 5 and 6 at the Powerton Station. The permit for Unit 7 for the Waukegan Station also authorizes Midwest Generation to convert the existing electrostatic precipitator to a cold-side design which will improve removal efficiency of particulate matter to satisfy the particulate control requirements of the CPS.

Testing of dry scrubbing using Trona on select Midwest Generation units has demonstrated significant reductions in SO_2 emissions. Use of this technology in conjunction with low sulfur coal is expected to require substantially less capital and time than the use of spray dryer absorber technology, but would likely result in higher ongoing operating costs and may consequently result in lower dispatch rates and competitiveness of Midwest Generation's plants, depending on competitors' costs.

Based on work to date, Midwest Generation estimates the cost of retrofitting all units, using dry scrubbing with sodium-based sorbents to comply with CPS requirements for SO_2 emissions, and the associated upgrading of existing particulate removal systems, would be approximately $1.2 billion in 2010 dollars. If these projects are undertaken, these expenditures would be incurred through 2018.

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Decisions regarding whether or not to proceed with the above projects or other approaches to compliance remain subject to a number of factors, such as market conditions, regulatory and legislative developments, and forecasted commodity prices and capital and operating costs applicable at the time decisions are required or made. Midwest Generation could also elect to shut down units, instead of installing controls, to be in compliance with the CPS. Therefore, decisions about any particular combination of retrofits and shutdowns it may ultimately employ also remain subject to conditions applicable at the time decisions are required or made. Due to existing uncertainties about these factors, Midwest Generation intends to defer final decisions about particular units for the maximum time available. Accordingly, final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital that is budgeted may not occur until 2012 for some of the units and potentially later for others. Preconstruction engineering and initial construction work may occur in 2011 in advance of a final decision to continue or complete the project.

Homer City Environmental Issues and Capital Resource Limitations

Homer City may be required to install additional environmental equipment on Units 1 and 2 to comply with environmental regulations the Clean Air Transport Rule ("Transport Rule") described below. Homer City projects that if SO_2 reduction technology becomes required, it may need to make capital commitments for such equipment several years in advance of the effective date of such requirements. Homer City continues to review technologies available to reduce SO_2 and mercury emissions and to monitor developments related to hazardous pollutants and other environmental regulations. The timing, selection of technology and required capital costs remain uncertain. The installation of environmental compliance equipment will be dependent on lessor decisions regarding the funding of these expenditures. 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. EME has no legal obligation to provide funding. Accordingly, final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital have not been made.

Greenhouse Gas Regulation

There have been a number of federal and state legislative and regulatory initiatives to reduce greenhouse gas ("GHG") emissions. Any climate change regulation or other legal obligation that would require substantial reductions in GHG emissions or that would impose additional costs or charges for GHG emissions could significantly increase the cost of generating electricity from fossil fuels, and especially from coal-fired plants, as well as the cost of purchased power, which could adversely affect Edison International's business. In the case of utilities, like SCE, these costs are generally borne by customers, whereas the increased costs for competitive generation, like EMG, must be recovered through market prices of electricity.

Significant developments include the following:

- In December 2009, the US EPA issued a final finding that certain GHGs, including carbon dioxide, threaten the public health and welfare. The US EPA has issued a proposed rule, known as the "GHG tailoring rule," which generally subjects newly constructed sources of GHG emissions and newly modified existing major sources to the Prevention of Significant Deterioration air permitting program (and later, the Title V permitting program), beginning in January 2011. The current program, which applies to only new or newly modified sources, is not expected to have an immediate effect on EMG's or SCE's existing generating plants. However, regulation of GHG emissions pursuant to this program could affect efforts to modify EMG's or SCE's facilities in the future, and could subject new capital projects to additional permitting and pollution control requirements that could delay such projects.

- Under a pending court settlement, the US EPA will propose performance standards for GHG emissions from new and modified power plants, and emissions guidelines for existing power plants, in July 2011, and will finalize such regulations by May 2012, with compliance dates expected to be in 2015 or 2016. The specific requirements will not be known until the regulations are finalized.

- In December 2010, the California Air Resources Board ("CARB") finalized regulations establishing a California cap-and-trade program, which include revisions to CARB's mandatory GHG emissions reporting regulation. The regulations and the cap-and-trade program itself are being challenged by various citizens' groups under the California Environmental Quality Act.

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In December 2010, the Supreme Court agreed to hear a case in which an appellate court found that judicial remedies for nuisance allegedly caused by GHG emissions were appropriate. The Supreme Court's decision may resolve the question of whether or not this type of litigation presents questions capable of judicial resolution or political questions that should be resolved by elected officials.

Transport Rule

In July 2010, the US EPA issued a Notice of Proposed Rulemaking for a proposed rule, known as the Transport Rule, which would require 31 eastern states (including Pennsylvania and Illinois) and the District of Columbia to reduce power plant emissions of NO_x and SO_2 substantially, starting in 2012, with additional reductions in 2014. The Transport Rule would replace the Clean Air Interstate Rule.

The Transport Rule is scheduled to be finalized in 2011. Depending on the approach to emissions allowance trading and allocation adopted by the US EPA, the Transport Rule may provide allowance allocations which are adequate for the plants' needs or may require the Midwest Generation plants to procure additional allowances, based on projected emissions using the Illinois CPS allowable emission rates. The Transport Rule may require the installation of additional environmental equipment to reduce SO_2 emissions at Units 1 and 2 of the Homer City facilities and, depending on the approach adopted, may also require Homer City to procure a significant amount of additional allowances or curtail operations if it is unable to do so on acceptable terms.

Hazardous Air Pollutant Regulations

In accordance with a consent decree entered in April 2010, the US EPA committed to proposing regulations by March 2011 limiting emissions of Hazardous Air Pollutants ("HAPs") from coal- and oil-fired electrical generating units that are major sources of HAPs, and to finalizing such regulations by November 2011. The emissions standards must be designed to achieve the maximum degree of emission reduction that the US EPA determines is achievable for the affected units, taking into account costs and non-air quality environmental and health benefits (also referred to as maximum available control technology, or MACT standard). Unlike the CAMR, the US EPA must regulate all of the HAPs emitted by these generating units. Compliance with the MACT standards will be required three years after the effective date of the final regulations. Until the US EPA's regulations are finalized, EMG cannot determine whether the actions it is taking to comply with other legal requirements (including the CPS) will be sufficient to address its obligations under the new regulations.

Water Quality

Clean Water Act

Regulations under the federal Clean Water Act govern critical parameters at generating facilities, such as the temperature of effluent discharges and the location, design, and construction of cooling water intake structures at generating facilities. The US EPA is rewriting these regulations following a 2009 U.S. Supreme Court decision that held that the US EPA may consider, but is not required to use, a cost-benefit analysis for this purpose. The Supreme Court set a deadline of March 2011 for draft regulations, which are to be finalized by July 2011. The new regulations will not allow the use of restoration to achieve compliance, but it is unknown whether they will use a cost-benefit analysis for determining the best technology available for compliance.

A new rule could have a material impact on SCE's and EMG's operations but neither SCE nor EMG can determine the financial impact until the final compliance criteria have been published. Significant capital expenditures may be required.

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

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 May 2010 the California State Water Resources Control Board issued a final policy, which establishes closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like SCE's San Onofre and many of the existing fossil-fueled power plants along the California coast. The final policy, which took effect on October 1, 2010, requires an independent engineering study to be

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completed prior to the fourth quarter of 2013 regarding the feasibility of compliance by California's two coastal nuclear power plants. Depending on the results of the study, the required compliance may result in significant capital expenditures at San Onofre and may affect its operations. The policy could 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. The policy may also significantly impact SCE's ability to procure generating capacity from fossil-fuel plants that use ocean water in once-through cooling systems, system reliability and the cost of electricity if other coastal power plants in California are forced to shut down or limit operations.

Coal Combustion Wastes

US EPA regulations currently classify coal ash and other coal combustion residuals as solid wastes that are exempt from hazardous waste requirements. In June 2010, the US EPA published proposed regulations relating to coal combustion residuals. Two different proposed approaches are under consideration. If the US EPA lists these residuals as special wastes subject to regulation as hazardous wastes, as proposed under one alternative, could require EMG and SCE to incur additional capital and operating costs without assurance that the additional costs could be recovered.

Note 11. Accumulated Other Comprehensive Income (Loss)

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

(in millions)	Unrealized Gain (Loss) on Cash Flow Hedges	Foreign Currency Translation Adjustment	Pension and PBOP Net Gain (Loss)	Pension and PBOP Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
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
Change for 2010	(89)		(17)	(7)	(113)
Balance at December 31, 2010	$ 16	$	$ (87)	$ (5)	$ (76)

Included in accumulated other comprehensive loss at December 31, 2010 was $26 million, net of tax, of unrealized gains on commodity-based cash flow hedges; and $10 million, net of tax, of unrealized loss related to interest rate hedges. The maximum period over which an interest rate hedge is designated is through March 31, 2026. The maximum period over which a commodity cash flow hedge is designated is through May 31, 2014.

Unrealized gains on commodity hedges consist of 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. Approximately $26 million of unrealized gains on cash flow hedges, net of tax, are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized gains will increase energy revenues 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.

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Note 12. Supplemental Cash Flows Information

Edison International's supplemental cash flows information is:

(in millions)	Years ended December 31, 2010	2009	2008
Cash payments (receipts) for interest and taxes:			
Interest net of amounts capitalized	$ 609	$ 661	$ 608
Tax payments	232	427	377
Details of assets acquired:			
Fair value of assets acquired	$ 1	$ 14	$
Liabilities assumed		3	
Net assets acquired	$ 1	$ 11	$
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	$ (378)	$	
Pollution-control bonds issued	378		
Details of capital lease obligations:			
Capital lease purchased	$	$ (223)	$
Capital lease obligation issued		223	
Consolidation of variable interest entities:			
Assets other than cash	$ (94)	$ 3	$ 3
Liabilities and noncontrolling interests	99	(4)	(4)
Deconsolidation of variable interest entities:			
Assets other than cash	$ 380	$	
Liabilities and noncontrolling interest	(476)		
Dividends declared but not paid:			
Common stock	$ 104	$ 103	$ 101
Preferred and preference stock of utility	13	13	13

In connection with certain wind projects acquired during the past four years, the purchase price included payments that were due upon the start and/or completion of construction. Accordingly, EMG accrued for estimated payments or made payments that were due upon commencement of construction and/or completion of construction scheduled during 2007 through 2011.

Note 13. Preferred and Preference Stock of Utility

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. SCE's outstanding shares are not subject to mandatory redemption. 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 was issued or redeemed in the years ended December 31, 2010 and 2009. 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 preference stock.

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Preferred stock and preference stock is:

(in millions, except per-share amounts)	Shares Outstanding	Redemption Price	December 31, 2010	2009
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:				
5.5% Series A (variable)	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 and B preference stock were issued in 2005 and the Series C preference stock was issued in 2006. SCE may, at its option, redeem Series A, B or C preference stock in whole or in part. No preference stock was redeemed in the last three years.

At December 31, 2010 accrued dividends related to SCE's preferred and preference stock were $13 million.

Note 14. 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.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts.

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

	December 31,	
(in millions)	**2010**	**2009**
Current:		
Regulatory balancing accounts	$ 213	$ 94
Energy derivatives	162	25
Other	3	1
	378	120
Long-term:		
Deferred income taxes net	1,855	1,561
Pensions and other postretirement benefits	1,097	1,014
Unamortized generation investment net	355	413
Unamortized loss on reacquired debt	268	287
Energy derivatives	177	357
Nuclear-related ARO investment net	154	258
Unamortized distribution investment net	105	
Regulatory balancing accounts	56	43
Other	280	206
	4,347	4,139
Total Regulatory Assets	$ 4,725	$ 4,259

SCE's regulatory assets related to energy derivatives are primarily an offset to unrealized losses on 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 assets 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 8). This amount will be recovered through rates charged to customers. SCE's unamortized generation investment includes nuclear assets related to San Onofre which are expected to be recovered by 2022, nuclear assets related to Palo Verde which are expected to be recovered by 2027 and SCE's unamortized coal plant investment which is being recovered through June 2016. Unamortized distribution investment includes legacy meters retired as part of the EdisonSmartConnect™ program which are expected to be recovered by 2025. Although SCE's unamortized generation and distribution 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 2010 and 2009. 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 28 years.

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Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

	December 31,	
(in millions)	**2010**	**2009**
Current:		
Regulatory balancing accounts	$ 733	$ 363
Other	5	4
	738	367
Long-term:		
Costs of removal	2,623	2,515
ARO	1,099	171
Regulatory balancing accounts	802	642
	4,524	3,328
Total Regulatory Liabilities	$ 5,262	$ 3,695

SCE's regulatory liability related to the ARO represents timing differences between the ARO and the assets of the nuclear decommissioning trust. The balance varies due to changes in the ARO as well as nuclear decommissioning trust investment activities. 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. These balances will be returned to ratepayers in a future ratemaking proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the ratemaking process, or be applied as otherwise directed by the CPUC.

Note 15. Other Investments

Nuclear Decommissioning Trusts

Future nuclear decommissioning costs of removal of nuclear assets are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $23 million per year included in SCE customer rates. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates. 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:

		Amortized Cost		Fair Value	
		December 31,		December 31,	
(in millions)	**Longest Maturity Dates**	**2010**	**2009**	**2010**	**2009**
Stocks		$ 895	$ 822	$ 2,029	$ 1,772
Municipal bonds	2049	706	545	790	634
Corporate bonds	2044	288	309	346	393

U.S. government and agency securities	2040	270	287	288	308
Short-term investments and receivables/payables	One-year	26	33	27	33
Total		$ 2,185	$ 1,996	$ 3,480	$ 3,140

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Proceeds from sales of securities (which are reinvested) were $1.4 billion, $2.2 billion and $3.1 billion for the years ended December 31, 2010, 2009 and 2008, respectively. Unrealized holding

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gains, net of losses, were $1.3 billion and $1.1 billion at December 31, 2010 and 2009, 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 years ended December 31:

(in millions)	2010	2009
Balance at beginning of period	$ 3,140	$ 2,524
Realized gains (losses) net	121	95
Unrealized gains (losses) net	148	526
Other-than-temporary impairments	(27)	(111)
Interest, dividends, contributions and other	98	106
Balance at end of period	$ 3,480	$ 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.

Leveraged Leases

Subsidiaries of EMG are lessors in power and affordable housing projects with terms of 25 to 30 years. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The acquisition costs of these facilities were $609 million at both December 31, 2010 and 2009. The equity investment in these facilities is generally 20% of the cost to acquire the facilities. The balance of the acquisition costs was funded by nonrecourse debt ($206 million as of December 31, 2010) collateralized by first liens on the leased property.

Net income from leveraged leases is:

	Years ended December 31,		
(in millions)	2010	2009	2008
Income from leveraged leases	$ 5	$ 14	$ 51
Tax effect of pre-tax income:			
Current	(19)	16	11
Deferred	18	(19)	(30)
Total tax (expense) benefit	(1)	(3)	(19)
Net income from leveraged leases	$ 4	$ 11	$ 32

Net investment in leveraged leases (including current portion) is:

	December 31,	
(in millions)	2010	2009

Rental receivables net	$	182	$	200
Estimated residual value		21		21
Unearned income		(37)		(42)
Investments in leveraged leases	$	166	$	179
Deferred income taxes		(177)		(193)
Net investments in leveraged leases	$	(11)	$	(14)

At December 31, 2010, leveraged lease receivables were primarily related to two power projects. The remaining leases relate to an airline. The allowance for credit reserves is based on a lease specific analysis which includes payment status, credit ratings and project cash flows. For leases in which there is a

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reasonable possibility that EMG will not collect its entire rent receivable balance, a probability-weighted approach for potential outcomes is used to determine the reserve.

Rental receivables are net of principal and interest on nonrecourse debt and credit reserves. Credit reserves were $5 million at December 31, 2010 and 2009. The current portion of rentals receivable was $22 million and $19 million at December 31, 2010 and 2009, respectively.

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 which is reflected in "Lease terminations and other" on Edison International's consolidated statements of income.

Note 16. Other Income and Expenses

Other income and expenses are as follows:

	Years ended December 31,		
(in millions)	**2010**	**2009**	**2008**
Other income:			
Equity AFUDC	$ 100	$ 116	$ 54
Increase in cash surrender value of life insurance policies	25	23	24
Energy settlement	5	9	3
Other	11	12	20
Total utility other income	141	160	101
Competitive power generation other income	7	11	12
Total other income	$ 148	$ 171	$ 113
Other expenses:			
Penalties	$	$	$ 59
Civic, political and related activities and donations	28	28	34
Marketing services	7	11	11
Other	16	10	19
Total utility other expenses	51	49	123
Competitive power generation other expenses		8	2
Total other expenses	$ 51	$ 57	$ 125

During 2009, the CPUC and FERC authorized the transfer of the Mountainview power plant to utility rate base which resulted in a one time, non-cash accounting benefit of approximately $46 million. This non-cash accounting benefit primarily resulted from the establishment of regulatory assets to recognize $50 million in differences in the accounting treatment for non-regulated and rate-regulated entities mainly related to equity AFUDC. There was no economic impact to customers from this change as compared to the FERC-approved power-purchase agreement. The transfer resulted in a $603 million increase in SCE's utility property, plant and equipment.

The 2008 penalty primarily resulted from a CPUC decision in September 2008 related to SCE incentives claimed under a CPUC-approved PBR mechanism.

Note 17. Business Segments

Edison International has two business segments for financial reporting purposes: an electric utility operation segment (SCE) and a competitive power generation segment (EMG). Prior to January 1, 2010, Edison International reported three business segments: an electric utility operations segment, a competitive power generation segment and a financial services segment. As a result of the termination of EMG's cross-border leases during 2009 and the continued decline of the remaining portfolio of the financial services segment, the financial services segment was no longer significant enough to report separately. Accordingly, the financial services segment has been combined into the competitive power generation segment for all periods presented. The significant accounting policies of the segments are the same as those described in Note 1.

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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	Parent and Other[2]	Consolidated Edison International
	Year ended December 31, 2010			
Operating revenue	$ 9,983	$ 2,429	$ (3)	$ 12,409
Depreciation, decommissioning and amortization	1,273	249		1,522
Interest and dividend income	7	30	(6)	31
Equity in income from partnerships and unconsolidated subsidiaries net		106		106
Interest expense net of amounts capitalized	429	264	10	703
Income tax expense (benefit) continuing operations	440	(36)	(50)	354
Income (loss) from continuing operations	1,092	219	(8)	1,303
Net income (loss) attributable to common shareholders	1,040[3]	224[1,4]	(8)[5]	1,256
Total assets	35,906	9,597	27	45,530
Capital expenditures	$ 3,780	$ 763	$	$ 4,543
	Year ended December 31, 2009			
Operating revenue	$ 9,965	$ 2,399	$ (3)	$ 12,361
Depreciation, decommissioning and amortization	1,178	239	1	1,418
Interest and dividend income	11	30	(9)	32
Equity in income (loss) from partnerships and unconsolidated subsidiaries net		89	(47)	42
Interest expense net of amounts capitalized	420	306	6	732
Income tax expense (benefit) continuing operations	249	(284)	(63)	(98)
Income (loss) from continuing operations	1,371	(391)	(28)	952
Net income (loss) attributable to common shareholders	1,226[3]	(395)[1,4]	18[5]	849
Total assets	32,474	9,543	(573)	41,444
Capital expenditures	2,999	283		3,282
	Year ended December 31, 2008			
Operating revenue	$ 11,248	$ 2,865	$ (1)	14,112
Depreciation, decommissioning and amortization	1,114	198	1	1,313
Interest and dividend income	22	48	(8)	62
Equity in income from partnerships and unconsolidated subsidiaries net		119	(88)	31
Interest expense net of amounts capitalized	407	288	5	700
Income tax expense (benefit) continuing operations	342	272	(18)	596
Income (loss) from continuing operations	904	560	(116)	1,348
Net income (loss) attributable to common shareholders	683[3]	561[1,4]	(29)[5]	1,215
Total assets	32,568	12,105	(58)	44,615
Capital expenditures	2,267	557		2,824

1 Includes earnings (losses) from discontinued operations of $4 million, ($7) million and less than one million for the years ended December 31, 2010, 2009 and 2008, respectively.

2 Includes amounts from Edison International (parent) and other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

3 Includes earnings of $95 million, $306 million, and zero for the years ended December 31, 2010, 2009 and 2008, respectively, related to the federal and state impacts of the Global Settlement. See Note 7.

4 Includes earnings (losses) of $52 million, $(610) million, and zero for the years ended December 31, 2010, 2009 and 2008, respectively, related to termination of Edison Capital's cross-border leases and the federal and state impacts of the Global Settlement on EMG. See Note 7.

5 Includes earnings of $28 million, $50 million, and zero for the years ended December 31, 2010, 2009 and 2008, respectively, related to the federal and state impacts of the Global Settlement. See Note 7.

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Note 18. Quarterly Financial Data (Unaudited)

(in millions, except per-share amounts)	2010 Total	Fourth	Third	Second	First
Operating revenue	$ 12,409	$ 3,069	$ 3,788	$ 2,741	$ 2,810
Operating income	2,126	414	862	351	498
Income from continuing operations	1,303	178	527	356	243
Income (loss) from discontinued operations net	4		(4)	1	6
Net income attributable to common shareholders	1,256	166	510	344	236
Basic earnings (loss) per share:					
Continuing operations	3.83	0.51	1.57	1.05	0.70
Discontinued operations	0.01		(0.01)		0.02
Total	3.84	0.51	1.56	1.05	0.72
Diluted earnings (loss) per share:					
Continuing operations	3.81	0.51	1.57	1.05	0.70
Discontinued operations	0.01		(0.01)		0.02
Total	3.82	0.51	1.56	1.05	0.72
Dividends declared per share	1.265	0.320	0.315	0.315	0.315
Common stock prices:					
High	39.37	39.37	35.15	34.74	35.82
Low	30.37	34.38	31.06	30.37	31.88
Close	38.60	38.60	34.39	31.72	34.17

(in millions, except per-share amounts)	2009 Total	Fourth	Third	Second	First
Operating revenue	$ 12,361	$ 3,050	$ 3,664	$ 2,834	$ 2,812
Operating income (loss)	1,398	439	768	(364)	553
Income from continuing operations	952	227	444	14	266
Income (loss) from discontinued operations net	(7)	(1)	(1)	(7)	3
Net income (loss) attributable to common shareholders	849	212	403	(16)	250
Basic earnings (loss) per share:					
Continuing operations	2.61	0.65	1.23	(0.03)	0.75
Discontinued operations	(0.02)			(0.02)	0.01
Total	2.59	0.65	1.23	(0.05)	0.76
Diluted earnings (loss) per share:					
Continuing operations	2.60	0.65	1.22	(0.03)	0.75
Discontinued operations	(0.02)			(0.02)	0.01
Total	2.58	0.65	1.22	(0.05)	