SOUTHERN CALIFORNIA
EDISON®
An *EDISON INTERNATIONAL*® Company

2009 Annual Report

Southern California Edison Company

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities serving a population of nearly 14 million via 4.9 million customer accounts in a 50,000-square-mile service area within Central, Coastal and Southern California.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

☐ **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 1-2313

SOUTHERN CALIFORNIA EDISON COMPANY

(Exact name of registrant as specified in its charter)

California **(State or other jurisdiction of incorporation or organization)**	**95-1240335** **(I.R.S. Employer Identification No.)**
2244 Walnut Grove Avenue **(P.O. Box 800)** **Rosemead, California** **(Address of principal executive offices)**	**91770** **(Zip Code)**

(626) 302-1212
(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
Capital Stock	
Cumulative Preferred	**American**
4.08%Series	**4.32%Series**
4.24%Series	**4.78%Series**

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 ☒ No ☐

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 ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant 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 ☐ No ☐

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. ☒

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 "accelerated filer," "large accelerated filer," and "smaller reporting company" in Rule 12b-12 of the Exchange Act. (Check One):

Large Accelerated Filer ☐ Accelerated Filer ☐ Non-accelerated Filer ☒ Smaller Reporting Company ☐

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

As of February 22, 2010, there were 434,888,104 shares of Common Stock outstanding, all of which are held by the registrant's parent holding company. The aggregate market value of registrant's voting and non-voting common equity held by non-affiliates was zero.

DOCUMENTS INCORPORATED BY REFERENCE

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

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

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 SCE's current expectations and projections about future events based on SCE'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 SCE 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, or that otherwise could impact SCE, include, but are not limited to:

- environmental laws and regulations, both at the state and federal levels, or changes in the application of those laws, that could require additional expenditures or otherwise affect the cost and manner of doing business;
- cost of capital and the ability to borrow funds and access to capital markets on reasonable terms;
- the cost and availability of electricity including the ability to procure sufficient resources to meet expected customer needs in the event of significant counterparty defaults under power-purchase agreements;
- changes in the fair value of investments and other assets;
- ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- changes in interest rates, rates of inflation, including those rates which may be adjusted by public utility regulators;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and price mitigation strategies adopted by Independent System Operators and Regional Transmission Organizations;
- risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage issues, failure, availability, efficiency, output, cost of repairs and retrofits, in each case of equipment, and availability and cost of spare parts;
- availability and creditworthiness of counterparties and the resulting effects on liquidity in the power and fuel markets and/or the ability of counterparties to pay amounts owed in excess of collateral provided in support of their obligations;
- cost and availability of labor, equipment and materials;

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

See "Risk Factors" in Part I, Item 1A of this report for additional information on risks and uncertainties that could cause results to differ from those currently expected or that otherwise could impact SCE 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 SCE's business. Forward-looking statements speak only as of the date they are made and SCE is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by SCE with the U.S. Securities and Exchange Commission.

GLOSSARY

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

AB	Assembly Bill
AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
Bcf	Billion cubic feet
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CARB	Clean Air Resources Board
CDWR	California Department of Water Resources
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DCR	Devers-Colorado River
DOE	U. S. Department of Energy
DRA	Division of Ratepayer Advocates
DWP	Los Angeles Department of Water & Power
EME	Edison Mission Energy
ERRA	energy resource recovery account
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGIC	Financial Guarantee Insurance Company
Four Corners	coal-fired electric generating facility located in Farmington, New Mexico where SCE holds a 48% ownership interest in Units 4 and 5
FTRs	firm transmission rights
GAAP	generally accepted accounting principles
Global Settlement	A settlement between Edison International and the IRS that resolved alleged deficiencies in Edison International's deferral of income taxes associated with certain of its cross-border, leveraged leases and all other outstanding tax disputes for open tax years 1986 through 2002.
GRC	General Rate Case
Illinois EPA	Illinois Environmental Protection Agency
Investor-Owned Utilities	SCE, SDG&E and PG&E
IRS	Internal Revenue Service
ISO	Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in this annual report
Moody's	Moody's Investors Service
Mohave	Mohave Generating Station
MRTU	Market Redesign Technical Upgrade
MW	megawatts
MWh	megawatt-hours
NAAQS	national ambient air quality standards

GLOSSARY
(Continued)

NERC	North American Electric Reliability Corporation
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NOx	nitrogen oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
Palo Verde	Palo Verde Nuclear Generating Station
PBOP(s)	postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
POD	Presiding Officer's Decision
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RICO	Racketeer Influenced and Corrupt Organization
ROE	return on equity
S&P	Standard & Poor's Ratings Services
San Onofre	San Onofre Nuclear Generating Station
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
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
The Tribes	Navajo Nation and Hopi Tribe
TURN	The Utility Reform Network
US EPA	U.S. Environmental Protection Agency
VIE(s)	variable interest entity(ies)

PART I

ITEM 1. BUSINESS

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

SCE makes available, free of charge on *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 Exchange Act, as soon as reasonably practicable after SCE electronically files such material with, or furnishes it to, the SEC. Such reports are also available on the SEC's internet website, *www.sec.gov*. The information contained on, or connected to, the Edison investor website is not incorporated by reference into this report.

Financial Information About Geographic Areas

All of SCE's revenue for the last three fiscal years is attributed to SCE's country of domicile, the United States. All of SCE's assets are located in the United States.

Regulation

CPUC

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

Resource Adequacy Requirements

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

Procurement of Renewable Resources

California law requires SCE to increase its procurement of energy from renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2010. Under the

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

FERC

SCE's wholesale operations (including sales of electricity into the wholesale markets) are subject to regulation by the Federal Energy Regulatory Commission ("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.

Reliability Standards

On July 20, 2006, the FERC certified the North American Electric Reliability Corporation ("NERC") as its Electric Reliability Organization to establish and enforce reliability standards for the bulk power system. Compliance with these standards became mandatory on June 18, 2007. SCE believes it has taken appropriate steps to be compliant with current NERC reliability standards that apply to its operations.

CEC

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

Nuclear Power Plant Regulation

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

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

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

Transmission and Substation Facilities Regulation

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

Relationship with Certain Affiliated Companies

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

Overview of Ratemaking Mechanisms

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

Base Rates

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

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

FERC Base Rates

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

Cost-Recovery Rates

Cost-recovery mechanisms allow SCE to recover its costs, but do not allow a return or profit. These mechanisms are used to recover SCE's costs of fuel, purchased-power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses, and depreciation expense related to certain projects. Although the CPUC authorizes balancing account mechanisms for such costs to refund or recover any differences between forecasted and actual costs, under- or over-collections in these balancing accounts do impact cash flows and can build rapidly.

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

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

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

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

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

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

CDWR-Related Rates

As a result of the California energy crisis, in 2001 the California Department of Water Resources ("CDWR") entered into contracts to purchase power for sale at cost directly to SCE's retail customers and issued bonds to finance those power purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of the Investor-Owned Utilities. SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. The CDWR-related charges and a portion of direct access exit fees that are remitted directly to the CDWR are not recognized as electric utility revenue by SCE and therefore have no impact on SCE's earnings; however, they do impact customer rates.

Competition

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

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

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

Purchased Power and Fuel Supply

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

Natural Gas Supply

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

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	2011
Conversion	2010
Enrichment	2013
Fabrication	2016

Spent Nuclear Fuel

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

Coal Supply

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

CAISO Wholesale Energy Market

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

The MRTU structure uses a nodal locational pricing model, which sets wholesale electricity prices at 3,000 different system points (nodes) that reflect local generation and delivery costs, as opposed to the previous system of three broad zonal prices. Generally, SCE schedules its electricity generation assets 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 IFM. 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 capacity, which results in transmission congestion charges and differences in prices at various nodes. The CAISO also offers congestion revenue rights or CRRs, a commodity that entitles the holder to receive (or pay) the value of transmission congestion between specific nodes, acting as an economic hedge against transmission congestion charges.

Properties

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

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

Generating Facility	Location 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 San Clemente	Nuclear	78.21%	2,150	1,760
Hydroelectric Plants (36)	Various	Hydroelectric	100%	1,176	1,176
Pebbly Beach Generating Station	Catalina Island	Diesel	100%	9	9
Mountainview	Redlands	Natural Gas	100%	1,050	1,050
Center Peaker	Norwalk	Gas fueled Combustion Turbine	100%	49	49
Mira Loma Peaker	Ontario	Gas fueled Combustion Turbine	100%	49	49
Grapeland Peaker	Rancho Cucamonga	Gas fueled Combustion Turbine	100%	49	49
Barre Peaker	Stanton	Gas fueled Combustion Turbine	100%	49	49
Palo Verde Nuclear Generating Station	Phoenix, AZ	Nuclear	15.8%	3,739	591
Four Corners Units 4 and 5	Farmington, NM	Coal-fired	48%	1,500	720
Total				9,820	5,502

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

Thirty-one of SCE's 36 hydroelectric plants (some with related reservoirs) are located in whole or in part on U.S.-owned lands pursuant to 30- to 50-year FERC licenses that expire at various times between 2010 and 2040. Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire projects upon payment of specified compensation. When existing licenses expire, the FERC has the authority to issue new licenses to third parties that have filed competing license applications, but only if their license application is superior to SCE's and then only upon payment of specified compensation to SCE. New licenses issued to SCE are expected to contain more restrictions and obligations than the expired licenses because laws enacted since the existing licenses were issued require the FERC to give environmental objectives greater consideration in the licensing process.

Substantially all of SCE's properties are subject to the lien of a trust indenture securing first and refunding mortgage bonds, of which approximately $6.40 billion in principal amount was outstanding on February 26, 2010.

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

Insurance

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

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

Seasonality

For a discussion of seasonality of SCE's revenues, see "Electric Utility Results of Operations—Supplemental Operating Revenue Information" in the MD&A.

Environmental Matters

SCE is subject to environmental regulation by federal, state and local authorities in the jurisdictions in which it operates. This regulation, including in the areas of air and water pollution, waste management, hazardous chemical use, noise abatement, land use, aesthetics, nuclear control and climate change, continues to result in the imposition of numerous restrictions on SCE's operation of existing facilities, on the timing, cost, location, design, construction, and operation by SCE of new facilities, and on the cost of mitigating the effect of past operations on the environment.

SCE's projected environmental capital expenditures and additional information about environmental matters affecting SCE appear in the MD&A under the heading "Liquidity and Capital Resources—Capital Investment Plan" and in "Item 8. SCE Notes to Consolidated Financial Statements—Note 6. Commitments and Contingencies—Environmental Remediation."

Climate Change

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

Federal Legislative/Regulatory Developments

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

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

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

State Legislative/Regulatory Developments

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

The second law, SB 1368, required the CPUC and the California Energy Commission ("CEC") to adopt greenhouse gas emission performance standards that restrict the ability of investor owned and publicly owned utilities, respectively to enter into long-term arrangements for the purchase of electricity. These standards must equal the performance of a combined-cycle gas turbine generator. The standards that have been adopted prohibit California load-serving entities, including SCE, from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, which includes most coal-fired plants. 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.

California law also requires SCE to increase its procurement of electricity generated from renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from such resources by no later than December 31, 2010 or such later date as flexible compliance requirements permit. In addition, in September 2009, Governor Schwarzenegger issued an executive order directing the CARB to adopt a regulation consistent with 33% of retail sellers' annual electricity sales being obtained from renewable energy sources by 2020. The executive order provides that the regulation may accelerate or expand the timeframe for compliance as well as increase the targeted percentage of annual electricity sales to be obtained from renewable resources, based on a thorough assessment of relevant factors.

Regional Initiatives

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

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

Litigation Developments

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

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

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

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

Emissions Data Reporting

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

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

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

Responses to Energy Demands and Future Greenhouse Gas Emission Constraints

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

SCE has developed and promoted several energy efficiency and demand response initiatives in the residential market, including an ongoing meter replacement program to help reduce peak energy demand; a rebate program to encourage customers to invest in more efficient appliances; subsidies for purchases of energy efficient lighting products; appliance recycling programs; widely publicized tips to customers for saving energy; and a voluntary demand response which offers customers financial incentives to reduce their electricity use. SCE is also replacing its electro-mechanical grid control systems with computerized devices that allow more effective grid management.

Corporate Governance Processes

SCE's Board of Directors regularly receives reports regarding environmental issues that affect SCE, including climate change issues.

Air Quality

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

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

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

Nitrogen Oxide and Sulfur Dioxide

Proposed NAAQS for Sulfur Dioxide

In November 2009, the US EPA proposed a new 1-hour NAAQS for SO_2. The new standard is proposed to be between 50 and 100 parts per billion. The US EPA is required by a consent decree to take final action by June 2, 2010. The proposed rule would require states to submit SIPs in 2014, with compliance by 2017.

Mercury – Clean Air Mercury Rule

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

Ozone and Particulates

National Ambient Air Quality Standards

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

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 BART or implement other control strategies to meet regional haze control requirements. The US EPA issued a final rulemaking on regional haze in 2005 requiring emission controls that constitute BART for industrial facilities that emit air pollutants which reduce visibility by causing or contributing to regional haze. These amendments required states to develop implementation plans to comply with BART by December 2007, to identify the facilities that will have to reduce SO_2, NO_x and particulate matter emissions, and then to set BART emissions limits for those facilities. Failure to do so results in a federal implementation plan.

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

New Source Review Requirements ("NSR")

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

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

Water Quality

Clean Water Act

Regulations under the federal Clean Water Act require permits for the discharge of pollutants into United States waters and permits for the discharge of storm water flows from certain facilities. The Clean Water Act also regulates the temperature of effluent discharges and the location, design, and construction of cooling water intake structures at generating facilities. California has a US EPA-approved program to issue individual or group (general) permits for the regulation of Clean Water Act discharges. California also regulates certain discharges not regulated by the US EPA.

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

The US EPA is currently rewriting its rule, and it is unknown whether the revised regulations will use cost-benefit analysis. Because there are no defined compliance targets absent a new rule, SCE is reviewing a wide range of possible control technologies. Although the new rule could have a material impact on SCE, until the final compliance criteria have been published, SCE can not reasonably determine the financial impact.

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

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

Hazardous Substances and Hazardous Waste

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

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

Coal Combustion Wastes

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

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

ITEM 1A. RISK FACTORS

Regulatory Risks

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

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

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

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

Many of SCE's power purchase contracts are tied to market prices for natural gas. Some of its contracts also are subject to volatility in market prices for electricity. SCE seeks to hedge its market price exposure to the extent authorized by the CPUC. SCE may not be able to hedge its risk for commodities on favorable terms or fully recover the costs of hedges through the rates it is allowed to charge its customers, which could adversely affect SCE's liquidity and results of operation.

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

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

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

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

Environmental Risks

SCE is subject to numerous environmental laws and regulations with respect to operation of its facilities. New laws and regulations could adversely affect SCE.

SCE is subject to extensive environmental regulations and permitting requirements that involve significant and increasing costs. SCE devotes significant resources to environmental monitoring, pollution control equipment and emission allowances to comply with existing and anticipated environmental regulatory requirements. However, the current trend is toward more stringent standards, stricter regulation, and more expansive application of environmental regulations. The U.S. Congress is considering several competing proposals to regulate greenhouse gas emissions. The U.S. Environmental Protection Agency has issued a finding that certain GHGs endanger the public health and welfare and are air pollutants that are subject to the Clean Air Act. In addition, the attorneys general of several states, including California, certain environmental advocacy groups, and numerous state regulatory agencies in the United States have been focusing considerable attention on greenhouse gas emissions from coal-fired power plants and their potential role in climate change. The adoption of laws and regulations to implement greenhouse act controls could adversely affect operations, particularly of the coal-fired plants.

The continued operation of SCE facilities, particularly the coal-fired facilities, may require substantial capital expenditures for environmental controls. In addition, future environmental laws and regulations, and future enforcement proceedings that may be taken by environmental authorities, could affect the costs and the manner in which SCE conducts business.

Furthermore, changing environmental regulations could make some units uneconomical to maintain or operate. If the affected subsidiaries cannot comply with all applicable regulations, they could be required to retire or suspend operations at such facilities, or to restrict or modify the operations of these facilities, and their business, results of operations and financial condition could be adversely affected.

Operating Risks

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

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

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

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

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

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

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

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

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

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

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

Financing Risks

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The principal properties of SCE are described above in Part I, Item 1. Business under the heading "Properties."

ITEM 3. LEGAL PROCEEDINGS

Catalina South Coast Air Quality Management District Potential Environmental Proceeding

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

Navajo Nation Litigation

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

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

EXECUTIVE OFFICERS OF THE REGISTRANT

Executive Officer[1]	Age at December 31, 2009	Company Position
Alan J. Fohrer	59	Chairman of the Board and Chief Executive Officer
John R. Fielder	64	President
Pedro J. Pizarro	44	Executive Vice President, Power Operations
Stephen E. Pickett	59	Senior Vice President and General Counsel
Ross Ridenoure	55	Senior Vice President and Chief Nuclear Officer
Linda G. Sullivan	46	Senior Vice President, Chief Financial Officer and Acting Controller
Lynda L. Ziegler	57	Senior Vice President, Customer Service

1 The term "Executive Officers" is defined by Rule 3b-7 of the General Rules and Regulations under the Securities Exchange Act of 1934, as amended.

None of SCE's executive officers is related to each other by blood or marriage. As set forth in Article IV of SCE's Bylaws, the elected officers of SCE are chosen annually by, and serve at the pleasure of, SCE'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 above officers have been actively engaged in the business of SCE and/or Edison International for more than five years, except for Mr. Ridenoure, and have served in their present positions for the periods stated below. Additionally, those officers who have had other or additional principal positions in the past five years had the following business experience during that period:

Executive Officer	Company Position	Effective Dates
Alan J. Fohrer	Chairman of the Board and Chief Executive Officer, SCE	June 2007 to present
	Chief Executive Officer, SCE	January 2002 to June 2007
John R. Fielder	President, SCE	October 2005 to present
	Senior Vice President, Regulatory Policy and Affairs, SCE	February 1998 to October 2005
Pedro J. Pizarro	Executive Vice President, Power Operations, SCE	April 2008 to present
	Senior Vice President, Power Procurement, SCE	May 2005 to March 2008
	Vice President, Power Procurement, SCE	January 2004 to May 2005
Stephen E. Pickett	Senior Vice President and General Counsel, SCE	January 2002 to present
Ross Ridenoure	Senior Vice President and Chief Nuclear Officer, SCE	June 2008 to present
	Vice President and Site Manager, SONGS, SCE	December 2007 to May 2008
	Vice President and Chief Nuclear Officer, Omaha Public Power District[1]	December 2003 to November 2007
Linda G. Sullivan	Senior Vice President, Chief Financial Officer and Acting Controller, SCE	July 2009 to present
	Vice President and Controller, Edison International	June 2005 to August 2009
	Vice President and Controller, SCE	June 2005 to June 2009
	Assistant Controller, SCE	March 2005 to May 2005
	Assistant Controller, Edison International	May 2002 to May 2005
Lynda L. Ziegler	Senior Vice President, Customer Service, SCE	March 2006 to present
	Vice President, Customer Programs and Services Division, SCE	May 2005 to February 2006
	Director, Customer Programs and Services Division, SCE	January 1999 to April 2005

1 Omaha Public Power District is a public electric utility in the State of Nebraska and is not a parent, subsidiary or affiliate of Edison International. Mr. Ridenoure served as Vice President and Chief Nuclear Officer.

PART II

ITEM 4. RESERVED

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

Certain information responding to Item 5 with respect to frequency and amount of cash dividends is included in "Item 8. SCE Notes to Consolidated Financial Statements Note 17. Quarterly Financial Data." As a result of the formation of a holding company described above in Item 1, all of the issued and outstanding common stock of SCE is owned by Edison International and there is no market for such stock.

Item 201(d) of Regulation S-K, "Securities Authorized For Issuance Under Equity Compensation Plans," is not applicable because SCE has no compensation plans under which equity securities of SCE are authorized for issuance.

ITEM 6. SELECTED FINANCIAL DATA

Selected Financial Data: 2005 – 2009

(Dollars in millions)	2009	2008	2007	2006	2005
Income statement data:					
Operating revenue	$ 9,965	$11,248	$10,233	$ 9,859	$ 9,065
Operating expenses	8,047	9,595	8,492	8,003	7,434
Purchased-power expenses	2,751	3,845	3,235	3,099	2,715
Income tax expense	249	342	337	438	292
Interest expense – net of amounts capitalized	420	407	429	399	362
Net income	1,371	904	1,063	1,102	1,083
Net income attributable to noncontrolling interests	94	170	305	275	334
Net income available for common stock	1,226	683	707	776	725
Ratio of earnings to fixed charges	4.30	3.42	3.35	3.97	3.80
Balance sheet data:					
Assets	$32,474	$32,568	$27,477	$26,110	$24,703
Gross utility plant	27,887	24,539	22,577	20,734	19,232
Accumulated depreciation	5,921	5,570	5,174	4,821	4,763
Short-term debt	—	1,893	500	—	—
Long-term debt including current portion	6,740	6,362	5,081	5,567	5,265
Other deferred credits and other long-term liabilities	1,652	902	1,158	834	745
Common shareholder's equity	7,446	6,513	6,228	5,447	4,930
Preferred and preference stock:					
Not subject to mandatory redemption	920	920	929	929	729
Capital structure:					
Common shareholder's equity	49.3%	47.2%	50.9%	45.6%	45.1%
Preferred stock:					
Not subject to mandatory redemption	6.1%	6.7%	7.6%	7.8%	6.7%
Subject to mandatory redemption	—	—	—	—	—
Long-term debt	44.6%	46.1%	41.5%	46.6%	48.2%

The selected financial data was derived from SCE'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.

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

MANAGEMENT OVERVIEW

Introduction

This overview is presented in three sections:

- Highlights of operating results;
- SCE's capital investment plan to maintain reliability and expand the capability of its distribution and transmission infrastructure, support initiatives in California to increase renewable energy, construct and replace generating assets and deploy advanced metering capability; and
- Environmental developments, including regulatory and legal developments related to greenhouse gases and once-through cooling.

Highlights of Operating Results

(in millions)	2009	2008	Change	2007
Net income available for common stock	$ 1,226	$ 683	$ 543	$ 707
Non-Core Items				
SCE Regulatory Items	46	(49)	95	31
Global Settlement	306	—	306	—
Total non-core items	352	(49)	401	31
Core Earnings	$ 874	$ 732	$ 142	$ 676

SCE's earnings are prepared in accordance with generally accepted accounting principles used in the United States. Management uses core earnings for financial planning and for analysis of performance. Core earnings are also used when communicating with analysts and investors regarding our earnings results to facilitate comparisons of SCE's performance from period to period. Core earnings is a non-GAAP financial measure and may not be comparable to those of other companies. Core earnings are defined as earnings attributable to SCE less income or loss from significant discrete items that management does not consider representative of ongoing earnings, such as: settlement of prior year tax liabilities and non-recurring regulatory or legal proceedings.

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

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

- The CPUC issued a decision in SCE's 2009 GRC, authorizing a $4.83 billion revenue requirement for 2009, an increase of $512 million from SCE's 2008 revenue requirement, effective January 1, 2009. The CPUC also authorized a methodology that would result in an approximate revenue requirement of $5.04 billion in 2010 and $5.25 billion in 2011.
- The FERC approved a settlement to the 2009 rate case effective March 1, 2009. The settlement provides for a transmission revenue requirement of $448 million, an increase of $136 million over the previously authorized amount.

Changes in non-core items include the following:

- An after-tax earnings benefit of $306 million in 2009 resulted from the Global Settlement with the Internal Revenue Service, including a $5 million tax benefit recorded in the fourth quarter from a revised estimate of federal interest related to the settlement. The Global Settlement resolved all outstanding federal tax disputes and affirmative claims for tax years 1986 through 2002.
- An after-tax non-cash benefit of $46 million was recorded in 2009 from the transfer of the Mountainview power plant to utility rate base pursuant to approvals by the CPUC and FERC.
- An after-tax charge of $49 million in 2008 from a decision by the CPUC disallowing certain amounts and imposing penalties under its performance-based ratemaking program for the period 1997 – 2003.

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

SCE Capital Program

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

- Upgrading and constructing new transmission lines to expand capacity to utilize renewable energy, including the Tehachapi, Devers-Colorado River and Eldorado-Ivanpah projects;
- Maintaining reliability and expanding capability of SCE's transmission and distribution system;
- Developing and installing up to 250 MW of utility-owned solar photovoltaic generating facilities (generally ranging in size from 1 to 2 MW each) on commercial and industrial rooftops and other space in SCE's service territory;
- Replacing steam generators at San Onofre intended to enable operations until at least the end of its initial license period in 2022; and
- Installing "smart" meters in approximately 5.3 million households and small businesses referred to as Edison SmartConnect™.

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

Environmental Developments

Greenhouse Gas Regulation Developments

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

Recent significant developments include the following:

- Legislation to regulate greenhouse gas emissions continues to be considered by Congress; however, the timing, content, and potential effects on SCE of any greenhouse gas legislation that may be enacted remain uncertain.
- In December 2009, the US EPA issued a final finding that certain greenhouse gases, including carbon dioxide, threaten the public health and welfare. The US EPA has issued a proposed rule, known as the "greenhouse gas tailoring rule," under which all new and major modifications of existing stationary sources emitting 25,000 metric tons of carbon dioxide equivalents annually, including power plants, would be required to include BACT to minimize their greenhouse gas emissions. Since the current proposal affects only new or modified sources, it is not expected to have any immediate effect, if adopted, on SCE's existing fossil-fuel generating stations, but it could affect the cost of new construction or modifications. US EPA could also use its authority in the future to regulate existing sources of greenhouse gas emissions. If controls are required to be installed at SCE's facilities in the future in order to reduce greenhouse gas emissions pursuant to regulations issued by the US EPA or others, the potential impact will depend on the nature of the controls applied, which remains uncertain.
- Three recent court cases addressed the question of whether power plants that emit greenhouse gases constituted public nuisances that could be held liable for damages or other remedies. In one case (in which Edison International, the parent company of SCE, is a named defendant): a California federal district court dismissed the plaintiffs' claims. In the other two, federal courts of appeals permitted the suits to go forward. Each of these differing results remains subject to appeal and thus the ultimate impact of these cases remains uncertain. SCE cannot predict whether these recent decisions will result in the filing of new actions with similar claims or whether Congress, in considering climate legislation, will address directly the availability of courts for these sorts of claims.

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

Once-Through Cooling

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

RESULTS OF OPERATIONS

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

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

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

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

Electric Utility Results of Operations

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

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

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

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

Utility Earning Activities

2009 vs. 2008

Utility earning activities were primarily affected by:

- Higher operating revenue of $514 million primarily due to the following:
  - $485 million increase resulting from the implementation of SCE's 2009 CPUC GRC decision, which authorized an increase of $512 million ($27 million of which

is reflected in utility cost-recovery activities) from SCE's 2008 revenue requirement effective January 1, 2009.

- $114 million increase resulting from the 2009 FERC approved rate case settlement effective March 1, 2009.
- $85 million decrease primarily due to the revenue requirements for medical, dental, and vision expenses and SCE's share of Palo Verde operation and maintenance expenses, which beginning in 2009 are reflected in utility cost recovery activities.
- In December 2009, the CPUC approved a payment of $26 million (compared to a $25 million payment in 2008) on SCE's 2006-2008 energy efficiency risk/reward incentive mechanism. SCE expects to recognize a final payment of approximately $27 million in 2010. The final payment, if any, may be reduced as a result of the final verification and review of the entire program cycle savings.

- Higher operation and maintenance expenses of $60 million primarily due to:
    - $105 million of higher transmission and distribution expenses primarily due to higher costs to support system reliability and infrastructure projects, increases in preventive maintenance work, as well as engineering costs;
    - $50 million of higher expenses related to regulatory and performance issues including the NRC requiring SCE to take action to provide greater assurance of compliance by San Onofre personnel with applicable NRC requirements and procedures. SCE is currently implementing plans to address the identified issues (see "Item 1. Business—Regulation—Nuclear Power Plant Regulation" for further discussion);
    - $50 million of higher expenses associated with new information technology system requirements and facility maintenance to support company growth programs;
    - $30 million of higher expenses resulting from the transfer of the Mountainview plant to utility rate base in July 2009, previously recognized in cost-recovery activities; partially offset by
    - $175 million of expenses which, beginning in 2009, are recovered through balancing accounts and are reflected in 2009 cost-recovery activities. SCE's 2009 GRC decision authorized balancing account treatment for medical, dental and vision expenses and SCE's share of Palo Verde operations and maintenance expenses.
- Higher depreciation expense of $80 million primarily resulting from increased capital investments including capitalized software costs.
- Lower net interest expense and other of $118 million primarily due to:
    - Lower other expenses of $71 million primarily due to a final charge of $60 million ($49 million after-tax)recorded in 2008 resulting from the CPUC decision on SCE's PBR mechanism as well as a $14 million decrease in civic, political and related activity expenditures, primarily related to spending on Proposition 7 in 2008, partially offset by a $8 million increase in donations. See "Item 8. SCE

Notes to Consolidated Financial Statements—Note 12. Other Income and Expenses" for further detail of other expenses.

- Higher other income of $63 million due to an increase in AFUDC – equity earnings primarily resulting from:
  - $50 million increase in AFUDC – equity earnings in the third quarter of 2009 related to the transfer of the Mountainview power plant to utility rate base. The 2009 CPUC GRC decision granted the authority to transfer the assets and liabilities of Mountainview Power Company, LLC to SCE, which was subsequently approved by the FERC and transferred in July 2009.
  - $12 million increase in AFUDC – equity earnings resulting from an increase in construction work in progress related to SCE's capital investment program.

  See "Item 8. SCE Notes to Consolidated Financial Statements—Note 12. Other Income and Expenses" for further detail of other income.
- Higher interest expense of $8 million primarily due to higher outstanding balances on long-term debt partially offset by lower interest expense on short-term borrowings. Due to an increase in cash flow from operations, including the positive cash impact from the Global Settlement and other tax timing differences, SCE was able to defer some of its expected financings in 2009 to support its growth programs.

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

2008 vs. 2007

Utility earning activities were primarily affected by:

- Higher operating revenue of $289 million primarily due to rate base related revenue growth, and authorized energy efficiency incentives. SCE recorded $25 million of energy efficiency revenues in 2008 in connection with the energy efficiency risk/reward incentive mechanism.
- Higher operation and maintenance expenses of $154 million primarily due to $60 million of higher generation expenses related to maintenance and refueling outage expenses at San Onofre and higher overhaul and outage costs at Four Corners and Palo Verde and $50 million of higher customer service expenses and administrative and general expenses primarily related to higher labor costs, increased uncollectible accounts and higher franchise fees and higher maintenance costs.
- Higher depreciation expense of $95 million primarily resulting from increased capital investments, including capitalized software costs, and a $17 million cumulative depreciation rate adjustment recorded in the second quarter of 2008.
- Higher net interest expense and other of $56 million primarily due to:
  - Higher other expenses of $79 million primarily due to a final charge of $60 million ($49 million after-tax) recorded in 2008 related to a decision received regarding

SCE incentives claimed under a CPUC-approved PBR mechanism. The 2008 variance was also due to an increase of $8 million for civic, political and related activity expenditures primarily related to spending on Proposition 7.

- Higher other income of $24 million primarily due to $10 million of proceeds received for corporate-owned life insurance policies and an $8 million increase in AFUDC – equity earnings resulting from an increase in construction work in progress related to SCE's capital investment program.
- Lower interest expense of $21 million primarily due to lower balancing account over-collections and lower interest rates applied to those over-collections. This decrease was partially offset by higher interest expense resulting from higher outstanding balances on long-term debt.
- Lower interest income of $22 million primarily due to lower balancing account under-collections and lower interest rates in 2008 compared to 2007 partially offset by higher interest income due to higher cash and equivalents and short-term investment balances.

Utility Cost-Recovery Activities

2009 vs. 2008

Utility cost-recovery activities were primarily affected by:

- Lower purchased power expense of $1.1 billion primarily due to: lower bilateral energy and QF purchases of $1.3 billion primarily due to lower natural gas prices and decreased kWh purchases; and lower firm transmission rights costs of $65 million due to implementation of the MRTU market. Realized losses on economic hedging activities were $344 million in 2009 and $60 million in 2008. Changes in realized losses on economic hedging activities were primarily due to settled natural gas prices being significantly lower than average fixed prices.
- Lower fuel expense of $679 million primarily due to lower costs at the Mountainview plant of $230 million and lower costs for the SCE Big 4 projects of $445 million, both resulting from lower natural gas costs in 2009 compared to 2008.
- Higher operation and maintenance expense of $81 million primarily related to $185 million of expenses which beginning in 2009 are recovered through balancing accounts and are reflected in 2009 cost recovery activities. SCE's 2009 GRC decision authorized balancing account treatment for medical, dental, and vision expenses and its share of Palo Verde operation and maintenance expenses. In addition, SCE recorded higher pension and PBOP expenses of $60 million due to the volatile market conditions experienced in 2008. These increases were partially offset by $50 million of lower energy efficiency costs, $85 million of lower transmission access and reliability service charges and $30 million of lower Mountainview expenses resulting from the transfer of the Mountainview plant to utility rate base in July 2009.

2008 vs. 2007

Utility cost-recovery activities were primarily affected by:

- Higher purchased power expense of $610 million due to: higher bilateral energy and QF purchases of $495 million, primarily due to higher natural gas prices and increased kWh purchases and higher ISO-related energy costs of $165 million. These increases were partially offset by $30 million of lower firm transmission rights costs. Realized losses on economic hedging were $60 million in 2008 and $132 million in 2007. Changes in realized losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007.
- Higher fuel expense of $209 million primarily due to higher costs at SCE's Mountainview plant of $85 million and higher costs at SCE's VIEs of $104 million, both resulting from higher natural gas prices in 2008 compared to 2007.

Supplemental Operating Revenue Information

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

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

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers, CDWR bond-related costs and a portion of direct access exit fees are remitted to the CDWR and are not recognized as revenue by SCE. The amounts collected and remitted to CDWR were $1.8 billion, $2.2 billion and $2.3 billion for the years ended December 31, 2009, 2008 and 2007, respectively.

Effective Income Tax Rates

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

Available Liquidity

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

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

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

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

Debt Covenant

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

Capital Investment Plan

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

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

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

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

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

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

Distribution Projects

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

Transmission Projects

SCE's has planned the following significant transmission projects:

- Tehachapi Transmission Project – An eleven segment project consisting of new and upgraded transmission lines and associated substations built primarily to enable the development of renewable energy generated primarily by wind farms in remote areas of eastern Kern County, California. Tehachapi segments one, two and a portion of segment three were completed and placed in service in 2009. The remainder of segment three is under construction and expected to be placed in service over the period 2011 – 2013. SCE continues to seek the necessary licensing permits for Tehachapi segments four through eleven, which are expected to be placed in service between 2011 and 2015, subject to receipt of licensing and regulatory approvals. SCE expects to invest $1.7 billion over the period 2010 – 2014 on this project. In November 2007, the FERC approved a 125 basis point ROE project adder, a 50 basis point incentive for CAISO participation, recovery of ROE and incentive adders during the CWIP phase, and recovery of abandoned plant costs (if any) on this project. SCE's requested 100% CWIP cost recovery is still pending FERC approval.
- Devers-Colorado River Project – A transmission project, also known as the California portion of the DPV2 project, involving the installation of a high voltage (500 kV) transmission line from Romoland, California to the Colorado River switchyard west of Blythe, California. The project is currently expected to be placed in service in 2013, subject to final licensing and regulatory approvals. Over the period 2010 – 2014, SCE expects to invest $658 million for this project in California. The DPV2 project includes the

transmission line through a portion of western Arizona, although SCE has deferred the Arizona portion while it continues to evaluate its transmission needs in western Arizona. In November 2007, the FERC approved a 125 basis point ROE project adder, a 50 basis point incentive for CAISO participation, recovery of ROE and incentive adders during the CWIP phase, and recovery of abandoned plant costs (if any) on the DPV2 project. Various parties have challenged SCE's ability to receive the DPV2 incentives.

- Eldorado-Ivanpah Transmission Project – A proposed 220/115 kV substation near Primm, Nevada and an upgrade of a 35-mile portion of an existing transmission line connecting the new substation to the Eldorado Substation, near Boulder City, Nevada. The project is currently expected to be placed in service in 2013, subject to necessary licensing and regulatory approvals. SCE expects to invest $469 million over the period 2010 – 2014 on this project. In December 2009, the FERC granted conditional approval of incentives on the project which included a 100 basis point ROE project adder, a 50 basis point incentive for CAISO participation, recovery of the ROE and incentive adders during the CWIP phase, and recovery of abandoned plant costs (if any) on this project. The approval was conditioned upon the approval of the CAISO and its finding that the project ensures reliability or reduces the cost of delivered power.
- Other capital investments consisting of $2.7 billion for other transmission to maintain reliability and expand capability of its infrastructure over the period 2010 – 2014. Included in these capital investments are other renewable projects in support of the 33% renewable procurement target.

Generation Projects

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

EdisonSmartConnect™

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

Solar Rooftop Program

In June 2009, the CPUC approved SCE's Solar Photovoltaic Program to develop up to 250 MW of utility-owned Solar Photovoltaic generating facilities generally ranging in size from

1 to 2 MW each, on commercial and industrial rooftops and other space in SCE's service territory. The decision allows SCE to recover its reasonable costs in customer rates and its CPUC-authorized rate of return on its investment. SCE expects to spend $1.0 billion over the period 2010 – 2014 on this project.

Regulatory Proceedings

Cost of Capital Mechanism

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

2010 FERC Rate Case

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

Dividend Restrictions

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

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

Income Tax Matters

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

Global Settlement

On May 5, 2009, Edison International and the IRS finalized the terms of a Global Settlement that resolved all of SCE's federal income tax disputes and affirmative claims through tax year 2002. See "Item 8. SCE Notes to Consolidated Financial Statements—Note 4. Income Taxes" for further discussion.

SCE expects that the Global Settlement will result in a positive cash impact over time. The following table provides the approximate cash flow expected over time:

(in millions)	
Taxes settled through December 31, 2009	$ 875
Estimated future net tax payments	(229)
Cash flow expected over time	$ 646

Repair Deductions

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

Margin and Collateral Deposits

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

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

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

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

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

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

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

Historical Consolidated Cash Flow

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

Condensed Consolidated Statement of Cash Flows

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

Cash Flows Provided by Operating Activities

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

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

- $468 million net cash inflow due to the increase in balancing account cash flows comprised of:
  - $1.3 billion net cash inflow due to the increase in ERRA balancing account cash flows (collections of approximately $450 million in 2009, compared to refunds of approximately $840 million in 2008). The ERRA balancing account was over-collected by $46 million, under-collected by $406 million and over-collected by $433 million at December 31, 2009, 2008, and 2007, respectively; partially offset by
  - $820 million net cash outflow related to all other regulatory balancing accounts which was primarily due to increased spending in 2009 compared to 2008 for public purpose and solar initiative programs and increased pension and PBOP contributions. In addition, a $200 million refund payment was received in 2008 related to public purpose programs.
- $250 million cash inflow benefit related to the American Recovery and Reinvestment Act of 2009 50% bonus depreciation provision.
- $192 million cash inflow benefit related to the change in its tax accounting method for certain repair costs incurred on SCE's transmission, distribution and generation assets.
- Higher cash inflow due to the increase in pre-tax income primarily driven by higher authorized revenue requirements resulting from the implementation of the 2009 CPUC and FERC GRC decisions.
- Timing of cash receipts and disbursements related to working capital items.

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

- $295 million net cash outflow due to the decrease in balancing account cash flows comprised of:
  - $745 million net cash outflow due to the decrease in ERRA balancing account cash flows (refunds of approximately $840 million in 2008, compared to refunds of approximately $95 million in 2007). The ERRA balancing account was under-collected by $406 million, over-collected by $433 million, and over-collected by $526 million at December 31, 2008, 2007, and 2006, respectively; partially offset by
  - $450 million net cash inflow related to all other regulatory balancing accounts which was primarily due a $200 million refund payment received in 2008 related to public purpose programs, $100 million refunded to ratepayers as a result of SCE's PBR decision, and a net $150 million in other balancing account overcollections.
- $240 million cash outflow due to the elimination of amounts collected in 2008 for the repayment of SCE rate reduction bonds. These bonds were fully repaid in December 2007. The bond payment is reflected in financing activities.
- Timing of cash receipts and disbursements related to working capital items, including tax-related items.

Cash Flows Provided (Used) by Financing Activities

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

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

- Repaid a net $1.9 billion of short-term debt, primarily due to the improvement in economic conditions that occurred during the second half of 2008.
- Paid $300 million in dividends to Edison International.
- Purchased $219 million of two issues of tax-exempt pollution control bonds and converted the issues to a variable rate structure. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.
- Repaid $150 million of first and refunding mortgage bonds.
- Issued $500 million of first refunding mortgage bonds due in 2039 and $250 million of first and refunding mortgage bonds due in 2014. The bond proceeds were used for general corporate purposes and to finance fuel inventories.

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

- Borrowed $1.4 billion under the line of credit to increase SCE's cash position to meet working capital requirements, if needed, during uncertainty over economic conditions during the second half of 2008.
- Issued $600 million of first refunding mortgage bonds due in 2038. The proceeds were used to repay SCE's outstanding commercial paper of approximately $426 million and for general corporate purposes.
- Issued $500 million of 5.75% first and refunding mortgage bonds due in 2014. The proceeds were used for general corporate purposes.
- Issued $400 million of 5.50% first and refunding mortgage bonds due in 2018. The proceeds were used to repay SCE's outstanding commercial paper of approximately $110 million and borrowings under the credit facility of $200 million, as well as for general corporate purposes.
- Paid $325 million in dividends to Edison International.
- Purchased $212 million of its auction rate bonds, converted the issue to a variable rate structure, and terminated the FGIC insurance policy. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.
- Paid $36 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

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

- Repaid $246 million of the remaining outstanding balance of its rate reduction bonds.
- Paid $135 million in dividends to Edison International.
- Paid $135 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).
- Issued $500 million of short-term debt to fund interim working capital requirements.

Net Cash Used by Investing Activities

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

Contractual Obligations and Contingencies

Contractual Obligations

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

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

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

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

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

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

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

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

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

Contingencies

SCE has contingencies related to FERC transmission incentives and CWIP proceedings, the Navajo Nation Litigation, nuclear insurance, and spent nuclear fuel, which are discussed in "Item 8. SCE Notes to Consolidated Financial Statements—Note 6. 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 of December 31, 2009, SCE identified 23 sites for remediation and recorded an estimated minimum liability of $39 million of which $5 million was related to San Onofre. SCE expects to recover 90% of its remediation costs at certain sites. See "Item 8. SCE Notes to Consolidated Financial Statements—Note 6. Commitments and Contingencies" for further discussion.

MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms. SCE uses derivative financial instruments, as appropriate, to manage its market risks.

Interest Rate Risk

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

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

Commodity Price Risk

SCE is exposed to commodity price risk which represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's hedging program reduces ratepayer exposure to variability in market prices related to SCE's power and gas activities. SCE recovers its related hedging costs, through the ERRA balancing account, subject to reasonableness review, and as a result, exposure to commodity price is not expected to impact earnings, but may impact cash flows.

Electricity price exposure arises from the following activities:

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

Natural gas price exposure arises from the following activities:

- Natural gas purchased for generation at Mountainview and peaker plants. The volume purchased may vary due to outages and dispatch based on SCE's management of its load requirements.
- Bilateral contracts where pricing is based on natural gas prices. Contract energy prices for some QFs are based on the monthly index price of natural gas delivered at the Southern California border. Approximately 37% of SCE's purchased power supply is subject to natural gas price volatility.
- Power contracts in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements. Volume may vary due to dispatch based on SCE's management of its load requirements or if the existing CDWR power contracts, which have related natural gas supply contracts, are novated or replaced and SCE becomes a party to such contracts. SCE is currently unable to predict which or how many existing CDWR contracts will be novated or replaced. However, due to the expected recovery through regulatory mechanisms these power procurement expenses are not expected to affect earnings.

Natural Gas and Electricity Price Risk

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

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

Fair Value of Derivative Instruments

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

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

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

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

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

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

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

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

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

Credit Risk

As part of SCE's procurement activities, SCE contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. If a counterparty were to default on its contractual obligations, SCE could be exposed to potentially volatile spot markets for buying replacement power or selling excess power. In addition, SCE would be exposed to the risk of non-payment of accounts receivable, primarily related to sales of excess energy and realized gains on derivative instruments. However, all of the contracts that SCE has entered into with counterparties are either entered into under SCE's short-term or long-term procurement plan which has been approved by the CPUC, or the contracts are approved by the CPUC before becoming effective. As a result of regulatory recovery mechanisms, losses from non-performance are not expected to affect earnings, but may temporarily affect cash flows.

To manage credit risk, SCE looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. SCE measures, monitors and mitigates credit risk to the extent possible. SCE manages the credit risk on the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. SCE's risk management committee regularly reviews and evaluates procurement credit exposure and approves credit limits for transacting with counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate. SCE anticipates future delivery of energy by counterparties, but given the current market condition, SCE cannot predict whether the counterparties will be able to continue operations and deliver energy under the contractual agreements.

The credit risk exposure from counterparties for power and gas trading activities is measured as the sum of net accounts receivable (accounts receivable less accounts payable) and the current fair value of net derivative assets (derivative assets less derivative liabilities) reflected on the balance sheet. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE's credit risk exposure from counterparties is based on a net exposure under these arrangements.

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

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

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

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

The credit risk exposure set forth in the above table is comprised of $7 million of net account receivables and $299 million representing the fair value, adjusted for counterparty credit reserves, of derivative contracts.

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

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

The accounting policies described below are considered critical to obtaining an understanding of SCE's consolidated financial statements because their application requires the use of significant estimates and judgments by management in preparing SCE's 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 if different estimates that could have been selected had been used could have a material impact on SCE's results of operations or financial position. For more information on SCE's accounting policies, see "Item 8. SCE Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies."

Rate Regulated Enterprises

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

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

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

Income Taxes

Nature of Estimates Required. As part of the process of preparing its consolidated financial statements, SCE 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 SCE's consolidated balance sheet.

SCE 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. SCE 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 SCE 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. SCE Notes to Consolidated Financial Statements—Note 4. Income Taxes" for a further discussion on income taxes.

Nuclear Decommissioning – ARO

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

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

- Decommissioning Costs. The estimated costs for labor, dismantling and disposal costs, energy and miscellaneous costs.
- Escalation Rates. Annual escalation rates are used to convert the decommissioning cost estimates in base year dollars to decommissioning cost estimates in future-year dollars. Escalation rates are primarily used for labor, material, equipment, and low level radioactive waste burial costs. SCE's current estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually.
- Timing. Cost estimates are based on an assumption that decommissioning will commence promptly after the current NRC operating licensees expire. The operating licenses currently expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2025 and 2027 for the Palo Verde units.
- Spent Fuel Dry Storage Costs. Cost estimates are based on an assumption that the DOE will begin to take spent fuel in 2015, and will remove the last spent fuel from the San Onofre and Palo Verde sites by 2045 and 2047, respectively. Costs for spent fuel monitoring are included until 2045 and 2047, respectively.
- Changes in decommissioning technology, regulation, and economics. The current cost studies assume the use of current technologies under current regulations and at current cost levels.

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

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

Pensions and Postretirement Benefits Other than Pensions

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

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

As of December 31, 2009, SCE's pension plans had a $3.4 billion benefit obligation and total expense for these plans was $107 million for 2009. As of December 31, 2009, SCE's PBOP plans had a $2.0 billion benefit obligation and total expense for these plans was $75 million for 2009. The following are critical assumptions used to determine expense for pension and other postretirement benefit obligations as of December 31, 2009:

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

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

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

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

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

SCE'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 have no plan assets.

Effect if Different Assumptions Used. Changes in the estimated costs or timing of pension and other postretirement benefit obligations, or in the assumptions and judgments used by management underlying these estimates, could have a material affect on the recorded expenses and liabilities. SCE's total annual contributions 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 $262 million. A one percentage point decrease in the discount rate would increase the projected benefit obligation for pension by $267 million. A one percentage point increase in the expected rate of return on pension plan assets would decrease the expense by $22 million.

A one percentage point increase in the discount rate for PBOP would decrease the projected benefit obligation by $225 million. A one percentage point decrease in the discount rate for the PBOP would increase the projected benefit obligation by $254 million. A one percentage point increase in the expected rate of return on PBOP plan assets would decrease the expense by $12 million. Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2009 by $211 million and annual aggregate service and interest costs by $14 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2009 by $193 million and annual aggregate service and interest costs by $13 million.

Accounting for Contingencies

Nature of Estimates Required. SCE records loss contingencies when it determines that the chance of a future event occurring is probable and when the amount of the loss can be reasonably estimated. Gain contingencies are recognized in the financial statements when they are realized.

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, SCE 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 advisers, and the experience gained from similar cases. SCE provides disclosure for material contingencies when there is a reasonable possibility that a loss or an additional loss may be incurred.

Effect if Different Assumptions Are 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 in the financial statements. See "Item 8. SCE Notes to Consolidated Financial Statements—Note 6. Commitments and Contingencies" for a discussion of contingencies.

NEW ACCOUNTING GUIDANCE

New accounting guidance are discussed in "Item 8. SCE 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 heading "Market Risk Exposures."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Shareholder of Southern California Edison Company

In our opinion, the consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in equity present fairly, in all material respects, the financial position of Southern California Edison Company (the "Company") and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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. We believe that our audits provide a reasonable basis for our opinion.

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

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

Consolidated Statements of Income

(in millions)	Years Ended December 31, 2009	2008	2007
Operating revenue	$ 9,965	$ 11,248	$ 10,233
Fuel	721	1,400	1,191
Purchased power	2,751	3,845	3,235
Operation and maintenance	3,154	3,013	2,838
Depreciation, decommissioning and amortization	1,178	1,114	1,011
Property and other taxes	244	232	217
Gain on sale of assets	(1)	(9)	—
Total operating expenses	8,047	9,595	8,492
Operating income	1,918	1,653	1,741
Interest income	11	22	44
Other income	160	101	89
Interest expense – net of amounts capitalized	(420)	(407)	(429)
Other expenses	(49)	(123)	(45)
Income before income taxes	1,620	1,246	1,400
Income tax expense	249	342	337
Net income	1,371	904	1,063
Less: Net income attributable to noncontrolling interests	94	170	305
Dividends on preferred and preference stock not subject to mandatory redemption	51	51	51
Net income available for common stock	$ 1,226	$ 683	$ 707

Consolidated Statements of Comprehensive Income

(in millions)	Years Ended December 31, 2009	2008	2007
Net income	$ 1,371	$ 904	$ 1,063
Other comprehensive income (loss), net of tax:			
Pension and postretirement benefits other than pensions:			
Net gain (loss) arising during period	(7)	2	(3)
Amortization of net gain (loss) included in net income	2	(2)	2
Prior service cost arising during period	—	1	—
Comprehensive income	1,366	905	1,062
Less: Comprehensive income attributable to noncontrolling interests	94	170	305
Comprehensive income attributable to SCE	$ 1,272	$ 735	$ 757

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

Consolidated Balance Sheets	**Southern California Edison Company**	
	December 31,	
(in millions)	2009	2008
ASSETS		
Cash and equivalents	$ 462	$ 1,611
Short-term investments	9	3
Receivables, less allowances of $53 and $39 for uncollectible accounts at respective dates	719	703
Accrued unbilled revenue	347	328
Inventory	337	365
Derivative assets	160	157
Regulatory assets	120	605
Deferred income taxes	78	147
Other current assets	97	283
Total current assets	2,329	4,202
Nonutility property – less accumulated depreciation of $744 and $765 at respective dates	324	953
Nuclear decommissioning trusts	3,140	2,524
Other investments	67	68
Total investments and other assets	3,531	3,545
Utility plant, at original cost:		
Transmission and distribution	22,214	20,006
Generation	2,667	1,819
Accumulated depreciation	(5,921)	(5,570)
Construction work in progress	2,701	2,454
Nuclear fuel, at amortized cost	305	260
Total utility plant	21,966	18,969
Derivative assets	187	74
Regulatory assets	4,139	5,414
Other long-term assets	322	364
Total long-term assets	4,648	5,852
Total assets	$ 32,474	$ 32,568

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

(in millions, except share amounts)	December 31, 2009	2008
LIABILITIES AND EQUITY		
Short-term debt	$ —	$ 1,893
Current portion of long-term debt	250	150
Accounts payable	1,058	948
Accrued taxes	9	340
Accrued interest	162	153
Customer deposits	238	227
Book overdrafts	224	224
Derivative liabilities	102	156
Regulatory liabilities	367	1,111
Other current liabilities	637	572
Total current liabilities	3,047	5,774
Long-term debt	6,490	6,212
Deferred income taxes	3,651	2,918
Deferred investment tax credits	97	101
Customer advances	119	137
Derivative liabilities	496	738
Pensions and benefits	1,681	2,485
Asset retirement obligations	3,198	3,007
Regulatory liabilities	3,328	2,481
Other deferred credits and other long-term liabilities	1,652	902
Total deferred credits and other liabilities	14,222	12,769
Total liabilities	23,759	24,755
Commitments and contingencies (Note 6)		
Common stock, no par value (560,000,000 shares authorized; 434,888,104 shares issued and outstanding at each date)	2,168	2,168
Additional paid-in capital	551	532
Accumulated other comprehensive loss	(19)	(14)
Retained earnings	4,746	3,827
Total common shareholder's equity	7,446	6,513
Preferred and preference stock not subject to mandatory redemption	920	920
Noncontrolling interests	349	380
Total equity	8,715	7,813
Total liabilities and equity	$ 32,474	$ 32,568

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

Consolidated Statements of Cash Flows	**Southern California Edison Company**		
	Years Ended December 31,		
(in millions)	2009	2008	2007
Cash flows from operating activities:			
Net income	$ 1,371	$ 904	$ 1,063
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	1,178	1,114	1,011
Regulatory impacts of net nuclear decommissioning trust earnings (reflected in accumulated depreciation)	158	(10)	143
Other amortization	109	97	95
Stock-based compensation	13	18	18
Deferred income taxes and investment tax credits	574	131	(111)
Changes in operating assets and liabilities:			
Receivables	(9)	14	214
Inventory	28	(74)	(51)
Margin and collateral deposits – net of collateral received	63	(16)	6
Other current assets	149	(35)	(201)
Accounts payable	43	(127)	42
Accrued taxes	(331)	298	61
Book overdrafts	—	20	64
Other current liabilities	26	(18)	(12)
Derivative assets and liabilities – net	(413)	634	(87)
Regulatory assets and liabilities – net	1,457	(2,946)	679
Other assets	48	275	(156)
Other liabilities	(395)	1,343	195
Net cash provided by operating activities	4,069	1,622	2,973
Cash flows from financing activities:			
Long-term debt issued	750	1,500	—
Long-term debt issuance costs	(11)	(20)	(1)
Long-term debt repaid	(154)	(3)	(207)
Bonds repurchased	(219)	(212)	(37)
Preferred stock redeemed	—	(7)	—
Rate reduction notes repaid	—	—	(246)
Short-term debt financing – net	(1,893)	1,393	500
Stock-based compensation – net	4	(15)	(51)
Distributions to noncontrolling interest	(125)	(236)	(210)
Dividends paid	(351)	(376)	(186)
Net cash provided (used) by financing activities	(1,999)	2,024	(438)
Cash flows from investing activities:			
Capital expenditures	(2,999)	(2,267)	(2,286)
Proceeds from sale of nuclear decommissioning trust investments	2,217	3,130	3,697
Purchases of nuclear decommissioning trust investments and other	(2,416)	(3,137)	(3,830)
Sales of short-term investments	1	—	7,069
Purchases of short-term investments	(7)	(3)	(7,069)
Restricted cash	—	—	56
Customer advances for construction and other investments	(15)	(10)	(3)
Net cash used by investing activities	(3,219)	(2,287)	(2,366)
Net increase (decrease) in cash and equivalents	(1,149)	1,359	169
Cash and equivalents, beginning of year	1,611	252	83
Cash and equivalents, end of year	$ 462	$ 1,611	$ 252

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

(in millions)	Equity Attributable to SCE: Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Preferred and Preference Stock	Noncontrolling Interests	Total Equity
Balance at December 31, 2006	$ 2,168	$ 383	$ (14)	$ 2,910	$ 929	$ 351	$ 6,727
Net income				758		305	1,063
Adoption of accounting guidance for uncertainty in income taxes				213			213
Other comprehensive loss			(1)				(1)
Dividends declared on common stock				(100)			(100)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(51)			(51)
Distributions to noncontrolling interest						(210)	(210)
Stock-based compensation – net		28		(79)			(51)
Noncash stock-based compensation and other		18		(5)			13
Change in classification of shares purchased to settle performance shares		78		(78)			—
Balance at December 31, 2007	$ 2,168	$ 507	$ (15)	$ 3,568	$ 929	$ 446	$ 7,603
Net income				734		170	904
Other comprehensive income			1				1
Dividends declared on common stock				(400)			(400)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(51)			(51)
Preferred stock redeemed, net of gain		2			(9)		(7)
Distributions to noncontrolling interest						(236)	(236)
Stock-based compensation – net		4		(19)			(15)
Noncash stock-based compensation and other		19		(5)			14
Balance at December 31, 2008	$ 2,168	$ 532	$ (14)	$ 3,827	$ 920	$ 380	$ 7,813
Net income				1,277		94	1,371
Other comprehensive loss			(5)				(5)
Dividends declared on common stock				(300)			(300)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(51)			(51)
Distributions to noncontrolling interests						(125)	(125)
Stock-based compensation – net		7		(3)			4
Noncash stock-based compensation and other		12		(4)			8
Balance at December 31, 2009	$ 2,168	$ 551	$ (19)	$ 4,746	$ 920	$ 349	$ 8,715

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

Notes to Consolidated Financial Statements

Significant accounting policies are discussed in Note 1, unless discussed in the respective Notes for specific topics.

Note 1. Summary of Significant Accounting Policies

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California. SCE is a wholly-owned subsidiary of Edison International.

Basis of Presentation

The consolidated financial statements include SCE, its subsidiaries and VIEs for which SCE is the primary beneficiary. Effective March 31, 2004, SCE began consolidating four cogeneration projects in accordance with authoritative guidance for VIEs. Intercompany transactions have been eliminated.

SCE's accounting policies conform to accounting principles generally accepted in the United States of America, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC. SCE applies authoritative guidance for rate-regulated enterprises to the portion of its operations in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of operating revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; and conversely the principles allow recording of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. See Note 11 for composition of regulatory assets and liabilities.

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

SCE has performed an evaluation of subsequent events through the date the financial statements were issued.

SCE's outstanding common stock is owned entirely by its parent company, Edison International.

AFUDC

AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. Currently, AFUDC debt and equity is capitalized during certain plant construction and reported in interest expense and other income, respectively. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. AFUDC-equity represents a method to compensate SCE for the estimated cost of equity used to finance utility plant additions and is recorded as part of construction in progress. AFUDC – equity was $116 million in 2009, $54 million in 2008 and $46 million in 2007. AFUDC – debt was $32 million in 2009, $27 million in 2008 and $24 million in 2007.

In 2007, FERC issued an order granting ROE incentive adders, recovery of the ROE and incentive adders during the construction phase (referred to as CWIP) and recovery of abandoned plant costs for three of SCE's transmission projects: DPV2, Tehachapi and Rancho Vista. In addition, the FERC granted an incentive for CAISO participation. The order permits SCE to include 100% of prudently-incurred capital expenditures in rate base during construction of the three projects and earn a return on equity, rather than capitalizing AFUDC.

Book Overdrafts

Book overdrafts represent timing difference associated with outstanding checks in excess of cash funds that are on deposit with financial institutions. SCE's ending daily cash funds are temporarily invested in cash equivalents until required for check clearings. SCE reclassifies the amount for checks issued but not yet paid by the financial institution, from cash to book overdrafts.

Cash and Equivalents

Cash equivalents included money market funds totaling $360 million and $1.53 billion at December 31, 2009 and 2008, respectively. The carrying value of cash equivalents equals the fair value due to maturities of less than three months. For further discussion of money market funds, see Note 10. Included in cash and equivalents is $92 million and $89 million at December 31, 2009 and 2008, respectively, for four projects that SCE is consolidating in accordance with authoritative accounting guidance for VIEs.

Deferred Financing Costs

Debt premium, discount and issuance expenses are deferred and amortized on a straight-line basis through interest expense over the life of each related issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. SCE had unamortized loss on reacquired debt of $287 million and $309 million at December 31, 2009 and 2008, respectively, reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. SCE had unamortized debt issuance costs of $50 million and $49 million at December 31, 2009 and 2008, respectively, reflected in "Other long-term assets" on the consolidated balance sheets. Amortization of deferred financing costs charged to interest expense was $27 million, $26 million and $26 million in 2009, 2008 and 2007, respectively.

Derivative Instruments and Hedging Activities

SCE records its derivative instruments on its consolidated balance sheets at fair value as either assets or liabilities unless they meet the definition of a normal purchase or sale or are classified as VIEs or leases. The derivative instrument fair values are marked to market at each reporting period. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Changes in the fair value of derivatives are expected to be recovered from or refunded to customers through regulatory mechanisms and therefore, SCE's fair value changes have no impact on purchased-power expense or earnings. SCE does not use hedge accounting for derivative transactions due to the regulatory accounting treatment.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when there is a legal right of offset, such as multiple contracts executed with the same counterparty under master netting arrangements. In addition, derivative positions are offset against margin and cash collateral deposits as discussed below in "Margin and Collateral Deposits." The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception is recorded on the consolidated balance sheets at fair value. Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases.

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, 2009, SCE's 13-month weighted-average common equity component of total capitalization was 49.8% resulting in the capacity to pay $271 million in additional dividends.

Impairment of Long-Lived Assets

SCE evaluates the impairment of its long-lived assets based on a review of estimated cash flows expected to be generated whenever events or changes in circumstances indicate the carrying amount of such investments or assets may not be recoverable. If the carrying amount of the asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, then an impairment loss is recognized. In accordance with authoritative guidance for rate-regulated enterprises, SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from the ratepayers.

Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Pursuant to an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed its federal and state income tax returns on a separate return basis.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes for each jurisdiction in which it operates. This involves estimating current period tax expense along with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within SCE's consolidated balance sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest income, interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income. Investment tax credits are deferred and amortized to income tax expense over the lives of the properties.

SCE believes that the positions it takes on filed tax returns are in accordance with tax laws. However, these positions are subject to interpretation by the IRS, state tax authorities and the courts. In accordance with authoritative guidance related to accounting for uncertainty in income taxes, SCE applies judgment to assess each tax position taken on filed tax returns and tax positions expected to be taken on future returns to determine whether a tax position is more likely than not to be sustained and, therefore, will be recognized in the financial statements. However, all temporary tax positions, whether or not the more likely than not to be sustained threshold is met, are recorded in the financial statements in accordance with the measurement principles of the authoritative guidance. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained. Management evaluates its income tax exposures at each reporting date and records valuation allowances and/or reserves as appropriate, which are reflected in the captions "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets.

Inventory

Inventory is stated at the lower of cost or market, cost being determined by the average cost method for fuel and materials and supplies.

Leases

Minimum lease payments under operating leases for vehicle, office space and other equipment is levelized over the terms of the leases.

Capital leases are reported as long-term obligations on the consolidated balance sheets under the caption "Other deferred credits and other long-term liabilities." In accordance with authoritative guidance for rate-regulated enterprises, SCE's capital lease amortization expense and interest expense are reflected in the caption "Purchased power" on the consolidated statements of income.

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers (reflected in "Other current assets" on the consolidated balance sheets) and cash received from counterparties (reflected in "Other current liabilities" on the consolidated balance sheets) as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the positions. In accordance with authoritative guidance which allows for netting of counterparty receivables and payables under a master netting arrangement, SCE presents a portion of its margin and cash collateral deposits net with its derivative positions on its consolidated balance sheets. Cash collateral provided to others that has been offset against derivative liabilities totaled zero and $72 million at December 31, 2009 and December 31, 2008, respectively. Cash collateral provided to others that has not been offset against derivative liabilities totaled $6 million and $17 million at December 31, 2009 and December 31, 2008, respectively. Cash collateral received from others that has not been offset against derivative assets totaled $59 million and $8 million at December 31, 2009 and December 31, 2008, respectively.

New Accounting Guidance

Accounting Guidance Adopted in 2009

General Principles

The FASB issued an accounting standard establishing the FASB Accounting Standards Codification (Codification) as the source of authoritative, nongovernmental U.S. GAAP superseding existing FASB, American Institute of Certified Public Accountants (AICPA), Emerging Issues Task Force (EITF) and related literature. Following this action, the FASB will not issue new standards in the form of Statements, FASB Staff Positions or EITF Abstracts. Instead, the FASB will issue Accounting Standards Updates. Two levels of U.S. GAAP will exist: authoritative and non-authoritative. The Codification is not intended to change U.S. GAAP or guidance issued by the U.S. Securities and Exchange Commission. SCE adopted the Codification effective July 1, 2009.

Subsequent Events

The FASB issued authoritative guidance that sets forth the period subsequent to the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; the circumstances under which an entity should recognize these events or transactions; and the disclosures that an entity should make. SCE adopted this guidance effective April 1, 2009. SCE also adopted revised disclosure requirements prescribed by an accounting standards update issued in 2010. The adoption had no impact on SCE's consolidated results of operations, financial position or cash flows.

Fair Value Measurements and Disclosures

The FASB issued an accounting standards update that provides additional guidance on how companies should measure the fair value of certain alternative investments such as hedge funds, private equity funds, venture capital funds and funds of funds. This update is designed to address concerns regarding how to appropriately adjust the Net Asset Value (NAV) of these investments to reflect specific attributes, including redemption restrictions and capital commitments. If the investee's underlying investments are measured at fair value at the investor's measurement date, this update allows investors to use NAV to estimate the fair value unless it is probable the investment will be sold at something other than NAV. If not calculated as of the reporting entity's measurement date, the NAV must be adjusted for significant market events. This update provides guidance on fair value hierarchy classification and also requires enhanced disclosures. SCE adopted this guidance on October 1, 2009. The adoption had no impact on its investments which primarily consist of the nuclear decommissioning trusts and certain investments in the defined benefit pension and PBOP plans and the related funded status of these plans recorded on SCE's consolidated balance sheets.

The FASB issued an accounting standards update that provides additional guidance on how companies should measure liabilities at fair value. While reaffirming the existing definition of fair value, the update reintroduced the concept of entry value into the determination of fair value. Entry value is the amount an entity would receive to enter into an identical liability. Under the new guidance, the fair value of a liability is not adjusted to reflect the impact of contractual restrictions that prevent its transfer. If the quoted price of a liability when traded as an asset includes the effect of a credit enhancement (i.e. a guarantee), this effect should be excluded from the measurement of the liability. SCE adopted this guidance effective October 1, 2009. The adoption had no impact on SCE's consolidated results of operations, financial position or cash flows.

The FASB issued authoritative guidance affirming the objective of a fair value measurement, which is to identify the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction at the measurement date between market participants ("exit price") under current market conditions. This includes guidance on identifying circumstances that indicate when there is no active market or transactions where the price inputs being used represent distressed or forced sales. If either of these conditions exists, this guidance provides additional direction for estimating fair value and requires disclosure of a change in valuation technique (and the related inputs) resulting from the application of this guidance and to quantify its effects, if practicable. This guidance also requires disclosures on a more disaggregated basis for investments in debt and equity securities measured at fair value. SCE adopted this guidance effective April 1, 2009. The adoption had no impact on SCE's consolidated results of operations, financial position or cash flows.

The FASB issued authoritative guidance requiring disclosures about the fair value of all financial instruments, for which it is practicable to estimate that fair value, for interim reporting periods as well as annual statements. SCE adopted this guidance effective April 1, 2009. Since this guidance impacted disclosures only, the adoption did not have an impact on SCE's consolidated results of operations, financial position or cash flows.

Effective January 1, 2009, SCE adopted authoritative guidance for nonrecurring fair value measurements of nonfinancial assets and liabilities. The adoption did not have a material impact on SCE's consolidated results of operations, financial position or cash flows.

Investments – Debt and Equity Securities

The FASB amended existing authoritative guidance which determines whether impairment is other than temporary for debt securities. Under this amended guidance, an entity writes down to fair value through earnings impaired debt securities that it currently intends to sell or for which it is more likely than not it will be required to sell before the anticipated recovery. If an entity does not intend and will not be required to sell a debt security but it is probable that the entity will not collect all amounts due, the entity will separate the other-than-temporary impairment into two components: 1) the amount due to credit loss would be recognized in earnings, and 2) the remaining portion would be recognized in other comprehensive income. SCE adopted this guidance effective April 1, 2009, resulting in increased disclosures. The adoption did not have an impact on SCE's consolidated results of operations, financial position or cash flows.

Compensation – Retirement Benefits

The FASB issued authoritative guidance requiring additional postretirement benefit plan asset disclosures by employers about the major categories of assets, the inputs and valuation techniques used to measure fair value, the level within the fair value hierarchy, the effect of using significant unobservable inputs (Level 3) and significant concentrations of risk. SCE adopted this guidance effective December 31, 2009. Since this guidance impacted disclosures only, the adoption did not have an impact on SCE's consolidated results of operations, financial position or cash flows.

Consolidation

The FASB issued authoritative guidance requiring an entity to present noncontrolling interests that reflect the ownership interests in subsidiaries held by parties other than the entity, within the equity section but separate from the entity's equity in the consolidated financial statements. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interests to be clearly identified and presented on the face of the consolidated balance sheets and statements of income; changes in ownership interests to be accounted for similarly as equity transactions; and when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary to be measured at fair value. SCE adopted this guidance effective January 1, 2009. In accordance with this guidance, SCE reclassified "Noncontrolling interests" of $380 million and "Preferred and preference stock of utility not subject to mandatory redemption" of $920 million at December 31, 2008 to a component of equity on SCE's consolidated balance sheet.

Derivatives and Hedging

The FASB issued authoritative guidance requiring additional disclosures related to derivative instruments, including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SCE adopted this guidance effective January 1, 2009. Since this guidance impacted disclosures only, the adoption did not have an impact on SCE's consolidated results of operations, financial position or cash flows.

Accounting Guidance Not Yet Adopted

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

In December 2009, the FASB issued an accounting standards update that changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an ability to direct the activities of the entity that most significantly impact the entity's economic performance and whether the entity has an obligation to absorb losses. This guidance requires a company to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. SCE will adopt this guidance effective January 1, 2010. SCE has determined that it will deconsolidate four QF contracts in which SCE has variable interests and which had total assets of $430 million at January 1, 2010. Deconsolidation will not result in a gain or loss.

Fair Value Measurements and Disclosures

In January 2010, the FASB issued an accounting standards update that provides for new disclosure requirements related to fair value measurements. New requirements include the separate disclosure of significant transfers in and out of Levels 1 and 2 and the reasons for the transfers. In addition, the Level 3 reconciliation of fair value measurements using significant unobservable inputs should include gross rather than net information about purchases, sales, issuances and settlements. The update clarified existing disclosure requirements for the level of disaggregation and inputs and valuations techniques. This guidance is effective January 1, 2010 except for the requirement to provide gross Level 3 activity which will be effective January 1, 2011. Since the guidance impacts disclosures only, the adoption will have no impact on SCE's consolidated results of operations, financial position or cash flows.

Nuclear Decommissioning

SCE recorded the fair value of its liability for AROs related to the decommissioning of its nuclear power facilities in 2003. At that time, SCE adjusted its nuclear decommissioning obligation, capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs and the recovery of costs through the rate-making process. Decommissioning cost estimates are updated in each Nuclear Decommissioning Cost Triennial Proceeding (NDCTP). Once a Commission decision is rendered, a revised ARO layer reflecting the updated cost estimate is established and accreted over the lives of San Onofre and Palo Verde.

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 initial plants' operating licenses are currently set to expire in 2022 for San Onofre Units 2 and 3, unless license renewal proves feasible, and 2024, 2025 and 2027 for Palo Verde units 1, 2 and 3, respectively. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. Amortization of the ARO asset (included within the unamortized nuclear investment) and accretion of the ARO liability are deferred as increases to the ARO regulatory liability account, resulting in no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The cost of removal amounts, in excess of fair value collected for assets not legally required to be removed, are classified as regulatory liabilities.

Due to regulatory recovery of SCE's nuclear decommissioning expense, SCE applies authoritative accounting guidance for rate-regulated enterprises to its nuclear decommissioning activities. As a result, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on electric utility revenue. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust asset and the related regulatory asset or liability and have no impact on electric utility revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the last day of each month and the last day of the previous month. If the fair value on both days is less than the cost for that security, SCE recognizes a loss for the other-than-temporary impairment. If the fair value is greater or less than the cost for that security at the time of sale, SCE recognizes a related realized gain or loss, respectively.

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. These costs are expensed as incurred.

Property and Plant

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and AFUDC.

In May 2003, the Palo Verde units returned to traditional cost-of-service ratemaking while San Onofre Units 2 and 3 returned to traditional cost-of-service ratemaking in January 2004. SCE's nuclear plant investments made prior to the return to cost-of-service ratemaking are recorded as regulatory assets on its consolidated balance sheets. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the rate-making treatment for these assets.

Estimated useful lives (authorized by the CPUC) and weighted-average useful lives of SCE's property, plant and equipment, are as follows:

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	25 years to 70 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	45 years
Other plant	5 years to 60 years	20 years

Nuclear fuel is recorded as utility plant (nuclear fuel in the fabrication and installation phase is recorded as construction in progress) in accordance with CPUC rate-making procedures. Nuclear fuel is amortized using the units of production method.

Depreciation of utility plant is computed on a straight-line, remaining-life basis. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.2% for 2009, 4.3% for 2008 and 4.2% for 2007. Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for AROs.

Asset Retirement Obligation

SCE accounts for its AROs in accordance with authoritative guidance which requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset in an amount equal to the liability. The liability is increased for accretion each period and the capitalized cost is depreciated over the useful life of the related asset. Settlement of an ARO liability for an amount other than its recorded amount results in a gain or loss. SCE's conditional AROs are recorded at fair value in the period in which they are incurred if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. AROs related to decommissioning of its nuclear power facilities are based on site-specific studies. Those site-specific studies are updated with each NDCTP. The initial establishment of a nuclear-related ARO is at fair value and results in a corresponding regulatory asset. Subsequent layers of an ARO are established for updated site-specific decommissioning cost estimates stemming from the approved NDCTP. See "Nuclear Decommissioning" above for further discussion.

Purchased-Power under CDWR Contracts

From January 17, 2001 to December 31, 2002, the CDWR signed long-term contracts that provide power for SCE's customers. SCE acts as a billing agent for the long-term contracts procured by the CDWR. Power purchased by the CDWR under these contracts for delivery to SCE's customers is not considered a cost to SCE.

Receivables

SCE records an allowance for uncollectible accounts, generally determined by the average percentage of amounts written-off in prior periods. SCE assesses its customers a late fee of 0.9% per month, beginning 21 days after the bill is prepared. Inactive accounts are written off after 180 days.

Regulatory Assets and Liabilities

SCE applies authoritative accounting principles for rate-regulated enterprises which applies in circumstances where regulators (in the case of SCE, CPUC and FERC) set rates at levels intended to recover the estimated costs of providing service, plus a return on its net investment, or rate base. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. SCE assesses, at the end of each reporting period, whether regulatory assets are probable of future recovery.

Related Party Transactions

Specified administrative services such as payroll and employee benefit programs, performed by SCE employees, are shared among all subsidiaries of Edison International, and the cost of these corporate support services are allocated to all subsidiaries. Costs are allocated based on one of the following formulas: relative amount of equity in investment, number of employees, or multi-factor method (operating revenue, operating expenses, total assets and number of employees). In addition, services of SCE employees are sometimes directly requested by an Edison International subsidiary and these services are performed for the subsidiary's benefit. Labor and expenses of these directly requested services are specifically identified and billed at cost.

Revenue Recognition

Operating revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each reporting period. Rates charged to customers are based on CPUC-authorized and FERC-approved revenue requirements. CPUC rates are implemented upon final approval. FERC rates are often implemented on an interim basis at the time when the rate change is filed. Revenue collected prior to a final FERC approval decision is subject to refund.

SCE recognizes revenue from base rates and cost-recovery rates, and could potentially recognize revenue or incur penalties under incentive mechanisms. Base rate activities provide for recovery of operation and maintenance costs, capital-related carrying costs and a return or profit, on a forecast basis, as well as a return on certain capital-related projects approved through balancing account mechanisms, separate from the GRC process. Cost-recovery rates provide for recovery for fuel, purchased power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses, and depreciation expense related to certain projects. There is no markup for return or profit for cost-recovery expenses (revenue recognized under cost-recovery rates is equal to expenses incurred under these mechanisms), except for a return on certain capital-related balancing account projects.

The CPUC-authorized decoupling revenue mechanisms allow differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers therefore such differences do not impact operating 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 operating revenue, but have an impact on earnings.

Power purchased by the CDWR related to long-term contracts it executed on behalf of SCE's customers between January 17, 2001 and December 31, 2002 is not considered a cost to SCE because SCE is acting as an agent for these transactions. Furthermore, amounts billed to ($1.8 billion in 2009, $2.2 billion in 2008 and $2.3 billion in 2007) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and a portion of direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as operating revenue by SCE.

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 operating revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as operating revenue were $102 million, $103 million and $104 million for the years ended December 31, 2009, 2008 and 2007, respectively. When SCE acts as an agent and when the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are being remitted to the taxing authorities and are not recognized as operating revenue.

Stock-Based Compensation

Stock options, performance shares, deferred stock units and, beginning in 2007, restricted stock units have been granted under Edison International's long-term incentive compensation programs. Edison International usually does not issue new common stock for equity awards settled. Rather, a third party is used to facilitate the exercise of stock options and the purchase and delivery of outstanding common stock for settlement of option exercises, performance shares and restricted stock units. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in Edison International's common stock. Deferred stock units granted to management are settled in cash, not stock and represent a liability. Restricted stock units are settled in common stock; however, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

SCE adopted fair value accounting for stock-based compensation on a prospective basis beginning in the first quarter of 2006. Fair value accounting is applied to any unvested awards outstanding as of January 1, 2006 and to all awards granted thereafter. Fair value accounting for stock-based compensation results in the recognition of expense for all stock-based compensation awards.

SCE recognizes stock-based compensation expense on a straight-line basis over the requisite service period. SCE recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, SCE recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006, to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation will be recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement.

Note 2. Derivative Instruments and Hedging Activities

SCE uses derivative financial instruments to manage financial exposure on its investments and fluctuations in commodity prices and interest rates. SCE manages these risks in part by entering into interest rate swap, cap and lock agreements, and forward commodity transactions, including options, swaps and futures. SCE is exposed to credit loss in the event of nonperformance by counterparties. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Commodity Price Risk

SCE is exposed to commodity price risk which represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's hedging program reduces ratepayer exposure to variability in market prices related to SCE's power and gas activities. SCE recovers its related hedging costs through the ERRA balancing account and as a result, exposure to commodity price is not expected to impact earnings, but may impact cash flows.

SCE's electricity price exposure arises from energy purchased and sold in the MRTU market as a result of differences between SCE's load requirements versus the amount of energy delivered from its generating facilities, existing bilateral contracts and CDWR contracts allocated to SCE.

Approximately 37% of SCE's purchased power supply is subject to natural gas price volatility. SCE's natural gas price exposure arises from purchasing natural gas for generation at Mountainview and peaker plants, bilateral contracts where pricing is based on natural gas prices (this includes contract energy prices for most renewable QFs which are based on the monthly index price of natural gas delivered at the southern California border), and power contracts in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements.

Natural Gas and Electricity Price Risk

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

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging activities at December 31, 2009:

Commodity	Unit of Measure	Economic Hedges
Electricity options, swaps and forward arrangements	MWh	14,868,034
Natural gas options, swaps and forward arrangements	Bcf	266
Congestion revenue rights[1]	MWh	195,367,422
Tolling arrangements[2]	MWh	116,398,216

1 In September 2007 and November 2008, the CAISO allocated CRRs for the period April 2009 through December 2017 based on SCE's load requirements. In addition, SCE participated in CAISO auctions for the procurement of additional CRRs. These CRRs meet the definition of a derivative.

2 In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced agreements with different project developers who have agreed to construct new southern California generating resources. SCE has entered into a number of contracts, of which five received regulatory approval in the fourth quarter of 2008 and are recorded as derivative instruments. The contracts provide for fixed capacity payments as well as pricing for energy delivered based on a heat rate and contractual operation and maintenance prices. However, due to uncertainty regarding the availability of required emission credits, some of the generating resources may not be constructed and the contracts associated with these resources could therefore terminate, at which time SCE would no longer account for these contracts as derivatives.

Fair Value of Derivative Instruments

The following table summarizes the gross and net fair values of commodity derivative instruments at December 31, 2009:

	Derivative Assets			Derivative Liabilities			
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	Net Liability
Non-trading activities							
Economic hedges	$ 160	$ 187	$ 347	$ 102	$ 496	$ 598	$ 251
Netting and collateral	—	—	—	—	—	—	—
Total	$ 160	$ 187	$ 347	$ 102	$ 496	$ 598	$ 251

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased-power expense and recovers these costs from ratepayers. As a result, realized gains and losses do not affect earnings, but may temporarily affect cash flows. Due to expected future recovery from ratepayers, unrealized gains and losses are deferred and are not recognized as purchased-power expense and therefore do not affect earnings. The results of derivative activities and related regulatory offsets are recorded in cash flows from operating activities in the consolidated statements of cash flows.

The following table summarizes the components of economic hedging activity:

	Years Ended December 31,		
(in millions)	2009	2008	2007
Realized gain (loss)	$ (344)	$ (60)	$ (132)
Unrealized gain (loss)	470	(638)	94

Contingent Features/Credit Related Exposure

Certain derivative instruments and power procurement contracts under SCE's power and natural gas hedging activities contain collateral requirements. SCE has historically provided collateral in the form of cash and/or letters of credit for the benefit of counterparties. These requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments, and other factors.

Certain of these power contracts contain a provision that requires SCE to maintain an investment grade credit rating from each of the major credit rating agencies, referred to as a "credit-risk-related contingent feature." If SCE's credit rating were to fall below investment grade, SCE may be required to pay the derivative liability or post additional collateral. The aggregate fair value of all derivative liabilities with these credit-risk-related contingent features as of December 31, 2009, was $91 million, for which SCE has posted no collateral to its counterparties. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, SCE would be required to post $4 million of collateral.

Note 3. Liabilities and Lines of Credit

Long-Term Debt

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from certain pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2009, SCE was in compliance with this debt covenant. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

The following table summarizes long-term debt (rates and terms are as of December 31, 2009):

(in millions)	December 31, 2009	2008
First and refunding mortgage bonds:		
2014 – 2039 (4.15% to 6.05% and variable)	$ 5,475	$ 4,875
Pollution-control bonds:		
2015 – 2035 (2.9% to 5.55% and variable)	1,196	1,196
Bonds repurchased	(468)	(249)
Debentures and notes:		
2010 – 2053 (5.06% to 7.625%)	557	557
Long-term debt due within one year	(250)	(150)
Unamortized debt discount – net	(20)	(17)
Total	$ 6,490	$ 6,212

Long-term debt maturities and sinking-fund requirements for the next five years are: 2010 – $250 million; 2011 – zero; 2012 – zero; 2013 – zero; and 2014 – $1.05 billion.

In late 2007 and early 2008, SCE purchased in the secondary market its auction rate bonds, totaling $249 million, and converted the issue from an auction-based reset process to a variable rate structure. In 2009, SCE purchased two issues of its tax-exempt bonds totaling $219 million that were subject to remarketing and also converted those issues to a variable rate structure. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.

Short-Term Debt

Short-term debt is generally used to finance fuel inventories, balancing account under-collections and general, temporary cash requirements including power purchase payments. At December 31, 2009, the outstanding short-term debt was zero. At December 31, 2008, the outstanding short-term debt was $1.89 billion at a weighted-average interest rate of 0.67%. This short-term debt was supported by a $2.5 billion credit line.

Credit Agreements

On March 17, 2009, SCE entered into a new $500 million 364-day revolving credit facility, terminating on March 16, 2010. The additional liquidity provided by the facility will be used to support SCE's ongoing power procurement-related needs.

In June 2009, SCE amended its $2.5 billion five-year credit facility to remove a subsidiary of Lehman Brothers Holdings as a lender which resulted in a reduction of the total commitment under the facility to $2.4 billion. This credit facility matures in February 2013 and provides four one-year options to extend by mutual consent.

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

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

Note 4. Income Taxes

The components of income tax expense from continuing operations by location of taxing jurisdiction are:

(in millions)	Years Ended December 31, 2009	2008	2007
Current:			
Federal	$ (82)	$ 53	$ 295
State	173	43	94
	91	96	389
Deferred:			
Federal	200	232	(31)
State	(42)	14	(21)
	158	246	(52)
Total	$ 249	$ 342	$ 337

The components of the net accumulated deferred income tax liability are:

(in millions)	December 31, 2009	2008
Deferred tax assets:		
Property and software related	$ 630	$ 497
Regulatory balancing accounts	229	436
Unrealized gains and losses	315	70
Decommissioning	173	168
Pensions and PBOPs	213	203
Other	507	439
Total	$ 2,067	$ 1,813
Deferred tax liabilities:		
Property-related	$ 4,371	$ 3,493
Capitalized software costs	286	231
Regulatory balancing accounts	257	433
Unrealized gains and losses	315	70
Decommissioning	155	148
Other	256	209
Total	$ 5,640	$ 4,584
Accumulated deferred income tax liability – net	$ 3,573	$ 2,771
Classification of accumulated deferred income taxes – net:		
Included in deferred credits and other liabilities	$ 3,651	$ 2,918
Included in total current assets	$ 78	$ 147

The federal statutory income tax rate is reconciled to the effective tax rate from continuing operations, net of income attributable to non-controlling interests, as follows:

	Years Ended December 31, 2009	2008	2007
Federal statutory rate	35.0%	35.0%	35.0%
State tax – net of federal benefit	4.4	3.5	4.4
Property-related	(4.2)	(6.1)	(1.0)
Tax reserve adjustments	2.0	0.7	(4.8)
ESOP dividend payment	(0.7)	(0.9)	(0.8)
Global tax settlement	(20.3)	—	—
Other	0.1	(0.4)	(2.0)
Effective tax rate	16.3%	31.8%	30.8%

The effective tax rate of 16.3% in 2009 included benefits related to both the Global Settlement and recognition of additional AFUDC – equity resulting from the transfer of the Mountainview power plant to utility rate base. The effective tax rate of 31.8% in 2008 included higher software deductions resulting from the implementation of SAP. The effective tax rate of 30.8% in 2007 includes reductions in liabilities for uncertain tax positions to reflect both the progress made in an administrative appeals process with the IRS related to the income tax treatment of certain costs associated with environmental remediation and to reflect a settlement of state tax audit issues. The CPUC requires flow-through rate-making treatment for the current tax benefit arising from certain property-related and other temporary differences, which reverse over time. The accounting treatment for these temporary differences results in recording regulatory assets and liabilities for amounts that would otherwise be recorded to deferred income tax expense.

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 from January 1 to December 31:

(in millions)	2009	2008	2007
Balance at January 1	$ 2,066	$ 1,950	$ 1,985
Tax positions taken during the current year			
Increases	14	111	63
Tax positions taken during a prior year			
Increases	200	162	124
Decreases	(212)	(157)	(222)
Decreases for settlements during the period	(1,586)	—	—
Balance at December 31	$ 482	$ 2,066	$ 1,950

Unrecognized tax benefits were reduced by $1.6 billion during 2009 primarily due to consummation of the Global Settlement as discussed below.

SCE believes it is reasonably possible that unrecognized tax benefits could be reduced by up to $68 million within the next twelve months from a settlement of state tax matters for periods through 2002.

As of December 31, 2009 and 2008, respectively, if recognized, $179 million and $60 million of the unrecognized tax benefits would impact the effective tax rate.

Accrued Interest and Penalties

The total amount of accrued interest and penalty related to SCE's income tax liabilities was $79 million and $120 million as of December 31, 2009 and 2008, respectively. After-tax interest expense (income), recognized in income tax expense was $(279) million, $14 million and $(24) million in 2009, 2008 and 2007 respectively.

Tax Years Subject to Examination

Edison International's federal income tax returns are currently under active examination by the IRS for tax years 2003 through 2006 and are subject to examination through tax years 2008.

Edison International's California and other state income tax returns are open for examination by the California Franchise Tax Board and other state tax authorities for tax years 1986 through 2008. The Franchise Tax Board is currently examining tax years through 2006.

Global Settlement

Edison International and the IRS finalized the terms of a Global Settlement on May 5, 2009. The Global Settlement resolves all of SCE's federal income tax disputes and affirmative claims through tax year 2002. During 2009, SCE recorded after-tax earnings of approximately $306 million, reflected in "Income tax expense" on the consolidated statements of income, primarily related to settlement of two affirmative claims associated with: (1) the taxation of balancing account over-collections; and (2) taxation of proceeds received in consideration for transferring control of SCE's transmission system to the CAISO and allowing direct access to SCE's distribution system, which were mandated as part of California's deregulation process. Both claims created positive tax timing differences that resulted in an interest refund from the IRS for prior period tax overpayments, but did not result in a permanent reduction in SCE's income tax liability. SCE expects an overall positive cash impact resulting from the Global Settlement of approximately $646 million over time, including the cash benefit of prior tax deposits of approximately $200 million.

Edison International is currently addressing the impact of the Global Settlement with state tax authorities. Resolution of such matters with such authorities may change the estimated cash and earnings impacts described above.

Note 5. Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $70 million in 2009, $65 million in 2008 and $61 million in 2007.

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 $81 million for the year ended December 31, 2010.

Volatile market conditions have affected the value of SCE's trusts established to fund its future long-term pension benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trusts declined 35% during 2008. This reduction in the value of plan assets resulted in a change in the pension plan funding status from overfunded to underfunded and will also result in increased future expense and increased future contributions. Improved market conditions in 2009 partially offset the impacts of the 2008 market conditions.

Changes in the plan's funded status also affect the assets and liabilities recorded on the consolidated balance sheet. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts. The Pension Protection Act of 2006 establishes new minimum funding standards and restricts plans underfunded by more than 20% from providing lump-sum distributions and adopting amendments that increase plan liabilities.

Information on plan assets and benefit obligations is shown below:

(in millions)	Years Ended December 31, 2009	2008
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 3,175	$ 3,106
Service cost	107	104
Interest cost	191	184
Amendments	21	—
Actuarial gain	57	(2)
Benefits paid	(162)	(217)
Projected benefit obligation at end of year	$ 3,389	$ 3,175
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,238	$ 3,459
Actual return (loss) on plan assets	551	(1,059)
Employer contributions	99	55
Benefits paid	(162)	(217)
Fair value of plan assets at end of year	$ 2,726	$ 2,238
Funded status at end of year	$ (663)	$ (937)
Amounts recognized in the consolidated balance sheets:		
Current liabilities	$ (5)	$ (5)
Long-term liabilities	(658)	(932)
	$ (663)	$ (937)
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	$ —	$ 1
Net loss	31	23
	$ 31	$ 24
Amounts recognized as a regulatory asset (liability):		
Prior service cost	$ 42	$ 33
Net loss	556	951
	$ 598	$ 984
Total not yet recognized as expense	$ 629	$ 1,008
Accumulated benefit obligation at end of year	$ 3,086	$ 2,898
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 3,389	$ 3,175
Accumulated benefit obligation	3,086	2,898
Fair value of plan assets	2,726	2,238
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	6.0%	6.25%
Rate of compensation increase	5.0%	5.0%

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years Ended December 31, 2009	2008	2007
Service cost	$ 107	$ 104	$ 100
Interest cost	191	184	171
Expected return on plan assets	(162)	(249)	(237)
Special termination benefits	—	—	2
Amortization of prior service cost	11	17	17
Amortization of net loss	54	3	3
Expense under accounting standards	$ 201	$ 59	$ 56
Regulatory adjustment – deferred	(94)	(5)	(3)
Total expense recognized	$ 107	$ 54	$ 53

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

(in millions)	Years Ended December 31, 2009	2008	2007
Net loss (gain)	$ 11	$ (2)	$ 5
Amortization of net loss	(4)	(3)	(3)
Total recognized in other comprehensive (income) loss	$ 7	$ (5)	$ 2
Total recognized in expense and other comprehensive income	$ 114	$ 49	$ 55

In accordance with authoritative guidance on rate-regulated enterprises, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of its postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost that will be amortized to expense in 2010 are $23 million and $8 million, respectively, including $5 million and zero respectively, expected to be reclassified from accumulated other comprehensive income.

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

	Years Ended December 31, 2009	2008	2007
Weighted-average assumptions:			
Discount rate	6.25%	6.25%	5.75%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected return on plan assets	7.5%	7.5%	7.5%

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

(in millions)	Years Ended December 31,
2010	$ 236
2011	246
2012	257
2013	265
2014	272
2015 – 2019	1,463

Postretirement Benefits Other Than Pensions

Most non-union employees retiring at or after age 55 with at least 10 years of service may be eligible for postretirement medical, dental, vision and life insurance and other benefits. Eligibility for a company contribution toward the cost of these benefits in retirement depends on a number of factors, including the employee's hire date. The expected contributions (all by the employer) to the PBOP trust are $43 million for the year ended December 31, 2010.

Volatile market conditions have affected the value of SCE'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 partially offset the impacts of the 2008 market conditions.

Changes in the plan's funded status also affect the assets and liabilities recorded on the 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.

Information on plan assets and benefit obligations is shown below:

(in millions)	Years Ended December 31, 2009	2008
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,247	$ 2,182
Service cost	28	38
Interest cost	116	130
Amendments	(63)	—
Actuarial gain	(233)	(26)
Plan participants' contributions	15	11
Medicare Part D subsidy received	5	5
Benefits paid	(104)	(93)
Benefit obligation at end of year	$ 2,011	$ 2,247
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,212	$ 1,815
Actual return (loss) on assets	256	(557)
Employer contributions	75	31
Plan participants' contributions	15	11
Medicare Part D subsidy received	5	5
Benefits paid	(104)	(93)
Fair value of plan assets at end of year	$ 1,459	$ 1,212
Fund status at end of year	$ (552)	$ (1,035)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$ (16)	$ (17)
Long-term liabilities	(536)	(1,018)
	$ (552)	$ (1,035)
Amounts recognized as a regulatory asset (liability):		
Prior service cost (credit)	$ (209)	$ (178)
Net loss	625	1,076
	$ 416	$ 898
Total not yet recognized as expense	$ 416	$ 898
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	6.0%	6.25%
Assumed health care cost trend rates:		
Rate assumed for following year	8.25%	8.75%
Ultimate rate	5.5%	5.5%
Year ultimate rate reached	2016	2016

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years Ended December 31, 2009	2008	2007
Service cost	$ 28	$ 38	$ 43
Interest cost	116	130	125
Expected return on plan assets	(81)	(122)	(119)
Special termination benefits	—	—	1
Amortization of prior service cost (credit)	(32)	(29)	(29)
Amortization of net loss	44	14	28
Total expense	$ 75	$ 31	$ 49

In accordance with authoritative guidance on rate-regulated enterprises, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of its postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost (credit) that will be amortized to expense in 2010 are $31 million and $(36) million, respectively.

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

	Years Ended December 31, 2009	2008	2007
Discount rate	6.25%	6.25%	5.75%
Expected return on plan assets	7.0%	7.0%	7.0%
Assumed health care cost trend rates:			
Current year	8.75%	8.75%	9.25%
Ultimate rate	5.5%	5.0%	5.0%
Year ultimate rate reached	2016	2015	2015

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2009 by $211 million and annual aggregate service and interest costs by $14 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2009 by $193 million and annual aggregate service and interest costs by $13 million.

The following benefit payments are expected to be paid:

(in millions)	Years Ended December 31, Before Subsidy[1]	Net
2010	$ 95	$ 89
2011	102	96
2012	108	102
2013	115	108
2014	123	115
2015 – 2019	720	668

1 Medicare Part D prescription drug benefits

Plan Assets

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. In 2009, the trusts' investment committee approved changes in target asset allocations. Target allocations for pension plan assets are 34% for U.S. equities, 17% for non-U.S. equities, 9% for alternative investments and 40% fixed income. Target allocation for PBOP plan assets are 45% U.S. equities, 14% non- U.S. equities, 2% private equities and 39% fixed income. SCE 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. SCE also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States Equities: Common and preferred stocks of large, medium, and small companies which are predominantly United States-based.

Non-United States Equities: Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.

Alternative Investments:

Private Equities: Limited partnerships that invest in non-publicly traded entities. The pension and PBOP target allocations are 6% and 2%, respectively.

Hedge funds: Funds that have target return and risk characteristics that are diversified among global equity, fixed income and currency markets. There is no systematic exposure to any market and investments are made in liquid instruments according to relative opportunities within and across markets. The pension target allocation is 3%.

Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities including municipal bonds, mortgage backed securities and corporate debt obligations. A small portion of the fixed income positions may be held in debt securities that are below investment grade.

Asset class portfolio weights are permitted to range within plus or minus 3%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to reallocate portfolio cash positions. Where authorized, a few of the plan's investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets

The overall expected long term rate of return on assets assumption is based on the long-term target asset allocation for plan assets and capital markets return forecasts for asset classes employed. A portion of the PBOP trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

Capital markets return forecasts are based on long-term strategic planning assumptions from an independent firm which uses its research, modeling and judgment to forecast rates of return for global asset classes. In addition, a separate analysis of expected returns is conducted. The estimated total return for fixed income is based on historic long-term United States government bonds data. The estimated total return for intermediate United States government bonds is based on historic and projected data. The estimated rate of return for U.S. and non-U.S. equity includes a 3% premium over the estimated total return for intermediate United States government bonds. The rate of return for private equity and hedge funds is estimated to be a 3% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Fair Value of Plan Assets

The PBOP Plan and the Southern California Edison Company Retirement Plan Trust (Master Trust) assets include investments in equity securities, U.S. treasury securities, other fixed-income securities, common/collective funds, mutual funds, other investment entities, foreign exchange and interest rate contracts, and partnership/joint ventures. Equity securities, U.S. treasury securities, mutual and money market funds are classified as Level 1 as fair value is determined by observable, unadjusted quoted market prices in active or highly liquid and transparent markets. Common/collective funds are valued at the net asset value (NAV) of shares held. Although common/collective funds are determined by observable prices, they are classified as Level 2 because they trade in markets that are less active and transparent. The fair value of the underlying investments in equity mutual funds and equity common/collective funds are based upon stock-exchange prices. The fair value of the underlying investments in fixed-income common/collective funds, fixed-income mutual funds and other fixed income securities including municipal bonds are based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information. Foreign exchange and interest rate contracts are classified as Level 2 because the values are based on observable prices but are not traded on an exchange. Future contracts trade on an exchange and therefore classified as Level 1. One of the partnerships is classified as Level 2 since this investment can be readily redeemed at NAV and the underlying investments are liquid publicly traded fixed-income securities which have observable prices. The remaining partnerships/joint ventures are classified as Level 3 because fair value is determined primarily based upon management estimates of future cash flows. Other investment entities are valued similarly to common collective funds and are therefore classified as Level 2. Substantially all of the registered investment companies are either mutual or money market funds and are therefore classified as Level 1 for the reasons noted above. The remaining fund in this category is readily redeemable at NAV and classified as Level 2 and is discussed further at footnote 7 to the pension master trust table.

Pension Plan

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2009 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks[1]	$ 678	$ —	$ —	$ 678
Common/collective funds[2]	—	612	—	612
Corporate bonds[3]	—	469	—	469
U.S. government and agency securities[4]	104	352	—	456
Partnerships/joint ventures[5]	—	101	240	341
Other investment entities[6]	—	135	—	135
Registered investment companies[7]	73	58	—	131
Interest-bearing cash	5	—	—	5
Foreign exchange contracts	—	6	—	6
Other	—	7	—	7
Total	$ 860	$ 1,740	$ 240	$ 2,840
Receivables and payables, net				17
Net plan assets available for benefits				2,857
SCE's share of net plan assets				$ 2,726

1 Corporate stocks are diversified. Performance is primarily benchmarked against the Russell Indexes (61%)and Morgan Stanley Capital International (MSCI) index (39%).

2 At December 31, 2009, 69% of the common/collective assets were invested in equity index funds that seek to track performance of the Standard and Poor's (S&P 500) Index (33%), Russell 200 and Russell 1000 indexes (26%) and the Morgan Stanley Capital International Europe, Australasia and Far East (EAFE) Index (10%). A non index fund representing 20% of this category as of December 31, 2009, invests in equity securities the Trustee believes are undervalued. Another fund representing 7% of this category is a global hedge fund that invests in short-term fixed income securities and seeks to exceed the performance of the Citigroup One-Month U.S. Treasury Bill Index.

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

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

5 Partnerships/joint venture Level 2 consists of a partnership which invests in publicly traded fixed income securities, primarily from the banking and finance industry and U.S. government agencies. Approximately 60% of the Level 3 partnerships are invested in asset backed securities including distressed mortgages. The remaining Level 3 partnerships are invested in several small private equity and venture capital funds. Investment strategies for these funds include branded consumer products, early stage technology, California geographic focus, and diversified US and non-US fund-of-funds.

6 At December 31, 2009, 64% of the other investment entity balance is invested in emerging market equity securities. About 17% of the assets in this category are invested in domestic mortgage backed securities. Most of the remaining funds invest in below grade fixed-income securities including foreign issuers.

7 At December 31, 2009, Level 1 of registered investment companies consists of a global equity mutual fund which seeks to outperform the Morgan Stanley Capital International Inc. World Total Return Index. Level 2 of this category is a hedge fund that invests through liquid instruments in a global diversified portfolio of equity, fixed income, interest rate, foreign currency and commodities markets.

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

The following table sets forth a summary of changes in the fair value of Level 3 investments for the year ended December 31, 2009:

(in millions)	2009
Fair value, net at January 1, 2009	$ 111
Actual return on plan assets:	
Relating to assets still held at end of period	34
Relating to assets sold during the period	6
Purchases and dispositions, net	89
Transfers in and /or out of Level 3	—
Fair value, net at December 31, 2009	$ 240

Postretirement Benefits Other than Pensions

The following table sets forth the PBOP Plan's financial assets that were accounted for at fair value as of December 31, 2009 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Common/collective funds[1]	$ —	$ 648	$ —	$ 648
Corporate stocks[2]	250	—	—	250
Registered investment companies[3]	213	—	—	213
Corporate notes and bonds[4]	—	151	—	151
U.S. government and agency securities[5]	39	28	—	67
Partnerships[6]	—	—	49	49
Interest bearing cash	14	—	—	14
Other[7]	3	74	—	77
Total	$ 519	$ 901	$ 49	$ 1,469
Receivables and payables, net				(10)
Combined net plan assets available for benefits				$ 1,459

1 At December 31, 2009, 61% of the common/collective assets are invested in a large cap index fund which seeks to track performance of the Russell 1000 index. At December 31, 2009, 23% of the assets in this category are in index funds which seek to track performance in the Morgan Stanley Capital International Europe, Australasia and Far East (EAFE) Index. 7% of this category is invested in a privately managed bond fund and 6% in a fund which invests in equity securities the fund manager believes are undervalued.

2 Corporate stock performance is primarily benchmarked against the Russell Indexes (67%) and the MSCI All Country World (ACWI) index (33%).

3 Registered investment companies consist of a money market fund and an investment grade corporate bond mutual fund.

4 Corporate notes and bonds are diversified and include approximately $10 million for commercial collateralized mortgage obligations and other asset backed securities.

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

6 Approximately 90% of the partnerships category is invested in asset backed securities including distressed mortgages.

7 Other includes $58 million of municipal securities at December 31, 2009.

At December 31, 2009, approximately 76% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

The following table sets forth a summary of changes in the fair value of PBOP Level 3 investments for the year ended December 31, 2009:

(in millions)	2009
Fair value, net at January 1, 2009	$ 12
Actual return on plan assets	
Relating to assets still held at end of period	12
Relating to assets sold during the period	1
Purchases and dispositions, net	27
Transfers in and /or out of Level 3	(3)
Fair value, net at December 31, 2009	$ 49

Stock-Based Compensation

On April 26, 2007, Edison International's shareholders approved a new incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. No additional awards were granted under Edison International's prior stock-based compensation plans on or after April 26, 2007, with all subsequent issuances being made under the new plan. The maximum number of shares of Edison International's common stock authorized to be issued or transferred pursuant to awards under the incentive plan as adopted was 8.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued ("carry-over shares"). On April 23, 2009, Edison International's shareholders approved certain amendments to the 2007 Performance Plan increasing such authorization by 13 million shares, resulting in an aggregate share limit of 21.5 million shares, plus the carry-over shares. As of December 31, 2009, Edison International had approximately 13 million shares remaining for future issuance under its stock-based compensation plans.

Total stock-based compensation expense, net of amounts capitalized (reflected in the caption "Other operation and maintenance" on the consolidated statements of income) was $20 million, $15 million and $21 million for 2009, 2008 and 2007, respectively. The income tax benefit recognized in the consolidated statements of income was $8 million, $6 million and $8 million for 2009, 2008 and 2007, respectively. Excess tax benefits included in "Stock-based compensation – net" in the financing section of the Consolidated Statements of Cash Flows were $7 million, $4 million and $28 million in 2009, 2008 and 2007, respectively.

Stock Options

Under various plans, SCE 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-based compensation expense associated with stock options was $8 million, $12 million and $12 million for 2009, 2008 and 2007, respectively.

Stock options granted in 2003 through 2006 accrue dividend equivalents for the first five years of the option term. Stock options granted in 2007 and later have no dividend equivalent rights except for options granted to Edison International's Board of Directors in 2007. Unless transferred to nonqualified deferral plan accounts, dividend equivalents accumulate without interest. Dividend equivalents are paid in cash after the vesting date. Edison International has discretion to pay certain dividend equivalents in shares of Edison International common stock. Additionally, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

The fair value for each option granted was determined as of the grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table.

	Years Ended December 31,		
	2009	2008	2007
Expected terms (in years)	7.4	7.4	7.5
Risk-free interest rate	2.8% – 3.5%	2.6% – 3.8%	4.6% – 4.8%
Expected dividend yield	3.6% – 5.0%	2.3% – 3.9%	2.1% – 2.4%
Weighted-average expected dividend yield	4.9%	2.5%	2.4%
Expected volatility	20% – 21%	17% – 19%	16% – 17%
Weighted-average volatility	20.6%	17.3%	16.5%

The expected term represents the period of time for which the options are expected to be outstanding and is primarily based on historical exercise and post vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a zero coupon U.S. Treasury issued STRIPS (separate trading of registered interest and principal of securities) whose maturity equals the option's expected term on the measurement date. Expected volatility is based on the historical volatility of Edison International's common stock for the lesser of 1) the period from January 1, 2003 through the last month-end prior to the grant date or 2) the length of the option's expected term. The volatility period used was 84 months, 72 months and 36 months at December 31, 2009, 2008 and 2007, respectively.

The following is a summary of the status of Edison International stock options granted to SCE employees:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2008	6,400,734	$ 34.58		
Granted	2,888,296	$ 25.21		
Expired	(57,248)	$ 44.00		
Forfeited	(155,792)	$ 32.11		
Exercised	(249,516)	$ 21.13		
Affiliate transfers – net	(77,459)	$ 33.63		
Outstanding at December 31, 2009	8,749,015	$ 31.91	6.57	
Vested and expected to vest at December 31, 2009	8,343,294	$ 31.87	6.48	$ 54,065,199
Exercisable at December 31, 2009	4,534,793	$ 30.80	4.83	$ 21,887,863

The weighted-average grant-date fair value of options granted during the 2009, 2008 and 2007 was $3.06, $10.19 and $11.36, respectively. The total intrinsic value of options exercised during 2009, 2008 and 2007 was $3 million, $13 million and $69 million, respectively. At December 31, 2009, there was $11 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 2009, 2008 and 2007 was $8 million, $12 million and $14 million, respectively.

Cash outflows to purchase Edison International shares in the open market to settle stock options exercised were $9 million, $30 million and $125 million for 2009, 2008 and 2007, respectively. Cash inflows from participants to exercise stock options were $6 million, $17 million and $56 million in 2009, 2008 and 2007, respectively. The tax benefit realized from options exercised for 2009, 2008 and 2007 was $1 million, $5 million and $28 million.

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2007, March 2008 and March 2009, and vest at the end of December 2009, 2010 and 2011, respectively. Performance shares awarded contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's common stock performance relative to the performance of a specified group of peer companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash 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. Stock-based compensation expense associated with performance shares was $3 million, less than a million and $6 million for 2009, 2008 and 2007, respectively.

Cash outflows to purchase Edison International shares in the open market to settle performance shares classified as equity awards was $5 million and $11 million for 2008 and 2007, respectively. There were no performance shares settled in 2009. In 2007, EIX changed the classification of the cash paid for the settlements of performance shares from common stock to retained earnings to conform with the classification for settlements of stock option exercises. The tax benefit realized from settlement of performance shares classified as equity awards for 2008 and 2007 was $2 million and $4 million, respectively.

The performance shares' fair value is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires a risk-free interest rate and an expected volatility rate assumption. The risk-free interest rate is based on the daily spot rate on the grant or valuation date on U.S. Treasury zero coupon issue or STRIPS (separate trading of registered interest and principal securities) with terms equal to the remaining term of the performance shares and is used as a proxy for the expected return for the specified group of companies. Expected volatility is based on the historical volatility of Edison International's (and the specified group of companies) common stock for the most recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

The risk-free interest rate used to determine the grant date fair values for the 2009, 2008 and 2007 performance shares classified as share-based equity awards was 1.3%, 3.9% and 4.8%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2009, 2008 and 2007 performance shares classified as share-based equity awards was 21.4%, 17.4% and 16.5%, respectively. The portion of performance shares classified as share-based liability awards are revalued at each reporting period. The risk-free interest rate used to determine the fair value as of December 31, 2009 was 1.1% and 0.5%, respectively, for 2009 and 2008 performance shares. The expected volatility rate used to determine the fair value as of December 31, 2009 was 21.9%. The risk-free interest rate used to determine the fair value as of December 31, 2008 was 0.8% and 0.4%, respectively, for 2008 and 2007 performance shares. The expected volatility rate used to determine the fair value as of December 31, 2008 was 19.2%. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2007 was 4.3% and 17.1%, respectively, for 2007 and 2006 performance shares. The total intrinsic value of performance shares settled during

2008 and 2007 was $11 million and $23 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2008 and 2007 of $3 million and $5 million, respectively. There were no performance shares settled in 2009. At December 31, 2009, there was $1 million (based on the December 31, 2009 fair value of performance shares classified as liability awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of approximately one year. The fair values of performance shares that vested during 2009, 2008 and 2007 were $1 million, $2 million and $8 million, respectively.

The following is a summary of the status of Edison International nonvested performance shares granted to SCE employees and classified as equity awards:

	Performance Shares	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2008	78,517	$ 56.45
Granted	102,633	$ 21.56
Forfeited	(7,616)	$ 28.94
Affiliate transfers – net	(930)	$ 57.94
Nonvested at December 31, 2009	172,604	$ 36.65

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2009, 2008 and 2007 was $21.56, $55.55 and $57.70, respectively.

The following is a summary of the status of Edison International nonvested performance shares granted to SCE employees and classified as liability awards (the current portion is reflected in the caption "Other current liabilities" and the long-term portion is reflected in "Accumulated provision for pensions and benefits" on the consolidated balance sheets):

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2008	78,517	
Granted	102,633	
Forfeited	(7,616)	
Affiliate transfers – net	(930)	
Nonvested at December 31, 2009	172,604	$ 19.88

Note 6. Commitments and Contingencies

Lease Commitments

In the ordinary course of business, SCE enters into various agreements to purchase power, resource capacity, and environmental attributes. SCE evaluates these agreements under authoritative accounting literature to determine whether such agreements contain a lease. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. Based on authoritative accounting guidance for leases, SCE then classifies each lease as capital or operating.

As of December 31, 2009, SCE recorded three power purchase agreements as capital leases. Gross capital leases reflected in "Utility plant" on the consolidated balance sheets were $248 million and $25 million at December 31, 2009 and 2008, respectively. The asset carrying amount, net of amortization, was $235 million and $16 million at December 31, 2009 and 2008, respectively. The related obligations were reflected on the consolidated balance sheets in "Other current liabilities" and "Other deferred credits and other long-term liabilities."

The following summarizes the estimated remaining commitments for noncancelable operating leases and all contracts that meet the requirements for capital leases:

(in millions)	Operating Leases – Power Contracts	Operating Leases – Other	Capital Leases
2010	$ 728	$ 51	$ 37
2011	770	48	33
2012	691	42	33
2013	793	37	33
2014	699	27	33
Thereafter	8,116	74	489
Total future commitments	$ 11,797	$ 279	$ 658
Amount representing executory costs	—	—	(144)
Amount representing interest	—	—	(279)
Net commitments	$ 11,797	$ 279	$ 235

Operating lease expense was $405 million in 2009, $375 million in 2008 and $336 million in 2007. The timing of SCE's recognition of the lease expense conforms to the ratemaking treatment for SCE's recovery of the cost of electricity. The amounts above do not include payments related to CDWR purchases for the benefit of SCE's customers, as SCE is acting as an agent for the CDWR.

Both capital and operating leases have varying terms, provisions and expiration dates. There were no sublease rentals and the contingent rentals for capital leases were less than $1 million for both 2009 and 2008.

Nuclear Decommissioning Commitment

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The liability to decommission SCE's nuclear power facilities is $3.1 billion as of December 31, 2009, based on site-specific studies performed in 2005 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 4.4% to 5.8%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates in the future. If the assumed return on trust assets is greater than estimated, funding amounts may be reduced through future decommissioning proceedings.

Decommissioning of San Onofre Unit 1 is underway and will be completed in three phases: (1) decontamination and dismantling of all structures and some foundations; (2) spent fuel storage monitoring; and (3) fuel storage facility dismantling, removal of remaining foundations, and site restoration. Phase one was completed in 2008. Phase two activities commenced January 1, 2009 and will continue until spent fuel is transferred to the DOE currently planned to begin in 2035. Phase three activities are planned to be performed concurrently with San Onofre Units 2 and 3 decommissioning projects. In February 2004, SCE announced that it discontinued plans to ship the San Onofre Unit 1 reactor pressure vessel to a disposal site until such time as appropriate arrangements are made for its permanent disposal. It will continue to be stored at its current location within the north industrial area of San Onofre. Final disposition of the Unit 1 reactor pressure vessel has therefore been planned for phase three of the Unit 1 decommissioning project.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds and are subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($61 million at December 31, 2009). Total expenditures for the decommissioning of San Onofre Unit 1 were $595 million from the beginning of the project in 1998 through December 31, 2009.

Decommissioning expense under the rate-making method was $46 million each in 2009, 2008 and 2007. The ARO for decommissioning SCE's active nuclear facilities was $3.1 billion and $2.9 billion at December 31, 2009 and 2008, respectively.

See "Nuclear Decommissioning Trusts" in Note 10 for discussion on fair value of the trust.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

SCE has power purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table below). There are no requirements to make debt-service payments.

Certain commitments for the years 2010 through 2014 are estimated below:

(in millions)	2010	2011	2012	2013	2014
Fuel supply	$ 180	$ 142	$ 180	$ 172	$ 119
Purchased power	395	422	602	702	682

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $45 million through 2016 (approximately $6 million per year).

Indemnities

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. 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, this water contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant's wastewater treatment "filter cake." Use of this impacted groundwater for cooling purposes was mandated by Mountainview's California Energy Commission permit. SCE has indemnified the City for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this guarantee.

Other Indemnities

SCE 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. SCE's obligations under these agreements may be limited in terms of time and/or amount, and in some instances SCE 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. SCE has not recorded a liability related to these indemnities.

Contingencies

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

Environmental Remediation

SCE is subject to numerous environmental laws and regulations, which typically require a lengthy and complex process for obtaining licenses, permits and approvals and require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

Possible developments, such as the enactment of more stringent environmental laws and regulations, proceedings that may be initiated by environmental and other regulatory authorities, cases in which new theories of liability are recognized, and settlements agreed to by other companies that establish precedent or expectations for the power industry, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures or operational expenditures or the ceasing of operations at certain facilities. There is no assurance that additional costs would be recovered from customers or that SCE's financial position, results of operations and cash flows would not be materially affected.

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

As of December 31, 2009, SCE's recorded estimated minimum liability to remediate its 23 identified sites was $39 million, of which $5 million was related to San Onofre. The ultimate costs to clean up SCE'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. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $178 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 34 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $10 million.

The CPUC allows SCE to recover 90% of its environmental remediation costs at certain sites, representing $34 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $36 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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 $11 million to $30 million. Recorded costs were $11 million, $29 million, and $25 million for 2009, 2008 and 2007, respectively.

Based on currently available information, SCE 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, SCE believes that costs ultimately recorded will not materially affect its results of operations, financial position or cash flows. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

Edison International's federal income tax returns are currently under active examination by the IRS for tax years 2003 through 2006 and are subject to examination through tax years 2008. Edison International's California and other state income tax returns remain open for tax years 1986 through 2008. As discussed in the section "Global Settlement" in Note 4, the Global Settlement was finalized on May 5, 2009 and effectively closed the federal income tax examination for tax years 1986 – 2002.

FERC Transmission Incentives and CWIP Proceedings

In November 2007, the FERC issued an order granting ROE incentive adders, recovery of the ROE and incentive adders during the CWIP phase and recovery of abandoned plant costs (if any) for three of SCE's transmission projects; DPV2, Tehachapi and Rancho Vista. The FERC approved, subject to refund, SCE's annual filing requests to collect its CWIP return of $37 million for 2008, $39 million for 2009, and $46 million for 2010. The 2008 and 2009 CWIP returns are currently being recovered in rates, subject to refund, and the 2010 CWIP return is expected to be recovered in rates beginning on June 1, 2010.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 against SCE, among other defendants, arising out of the coal supply agreement for Mohave. Subsequently, the Hopi Tribe was added as an additional plaintiff. The Navajo's complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion. In April 2009, in a related case filed in December 1993 against the U.S. Government, the U.S. Supreme Court found that the Navajo Nation did not have a claim for compensation. SCE cannot predict the outcome of the Tribes' complaints against SCE.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.6 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($375 million). The balance is covered by a loss sharing program among nuclear reactor licensees. If a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site, all nuclear reactor licensees could be required to contribute their share of the liability in the form of a deferred premium.

Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 million per incident in any one year. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further federal revenue.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately $45 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31,

1998. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. Currently, both San Onofre and Palo Verde have interim storage for spent nuclear fuel on site sufficient for the current license period.

On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. The trial was completed in April 2009 but no decision has been issued. SCE cannot predict the outcome of this proceeding or when a decision will be issued by the Court.

Note 7. Accumulated Other Comprehensive Income

SCE's accumulated other comprehensive income consists of:

(in millions)	Pension and PBOP – Net (Gain) Loss	Pension and PBOP – Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2007	$ (14)	$ (1)	$ (15)
Change for 2008	1	—	1
Balance at December 31, 2008	(13)	(1)	(14)
Change for 2009	(5)	—	(5)
Balance at December 31, 2009	$ (18)	$ (1)	$ (19)

Note 8. Property and Plant

Nonutility Property

Nonutility property included in the consolidated balance sheets is comprised of:

	December 31,	
(in millions)	2009	2008
Furniture and equipment	$ 3	$ 5
Building, plant and equipment	1,034	1,681
Land (including easements)	28	30
Construction in progress	3	2
	1,068	1,718
Accumulated provision for depreciation	(744)	(765)
Nonutility property – net	$ 324	$ 953

On March 12, 2009, the CPUC issued a final decision in SCE's 2009 GRC, authorizing the transfer of the Mountainview power plant to utility rate base. SCE received FERC and other necessary approvals, and on July 1, 2009, terminated the FERC-approved power-purchase agreement between Mountainview Power Company, LLC and SCE, and transferred assets and liabilities valued at $680 million and $173 million, respectively. The transfer resulted in a $603 million increase in SCE's utility plant (primarily generation plant) with a corresponding decrease in nonutility property (primarily building, plant and equipment). In addition, SCE recognized a one time, non-cash accounting benefit of approximately $46 million primarily resulting from the establishment of regulatory assets to recognize differences in the accounting treatment for non-regulated and rate-regulated entities mainly related to AFUDC – equity. There was no economic impact to customers from this change as compared to the FERC-approved power-purchase agreement; as these amounts would have been recognized over the life of that agreement and have no impact on cash flows.

Asset Retirement Obligations

In 2003, SCE recorded the fair value of its liability for legal AROs, which are primarily related to the decommissioning of SCE's nuclear power facilities. SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs and the recovery of the costs through the rate-making process. SCE has collected in rates amounts for the future cost of removal of its nuclear assets and has placed those amounts in independent trusts. For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6 and "Nuclear Decommissioning Trusts" in Note 10.

A reconciliation of the changes in the ARO liability is as follows:

(in millions)	2009	2008	2007
Beginning balance	$ 3,007	$ 2,877	$ 2,749
Accretion expense	186	175	168
Revisions	6	(10)	3
Liabilities settled	(1)	(35)	(43)
Ending balance	$ 3,198	$ 3,007	$ 2,877

The ARO liability as of December 31, 2009 includes an ARO liability of $3.1 billion related to nuclear decommissioning.

Note 9. Supplemental Cash Flows Information

The following is SCE's supplemental cash flows information:

(in millions)	Years Ended December 31, 2009	2008	2007
Cash payments(receipts) for interest and taxes:			
Interest – net of amounts capitalized	$ 352	$ 303	$ 292
Tax payments(refunds) – net	(658)	251	299
Noncash investing and financing activities:			
Details of obligation under capital leases:			
Capital lease purchased	$ (223)	$ —	$ (10)
Capital lease obligation issued	223	—	10
Dividends declared but not paid:			
Common stock	$ 100	$ 100	$ 25
Preferred and preference stock not subject to mandatory redemption	13	13	13

Note 10. Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (referred to as an "exit price"). Fair value for a liability should reflect the entity's non-performance risk. Fair value is determined using a hierarchy to prioritize the inputs to valuation models. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are:

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

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

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

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

The fair value of derivative contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities, and other factors. Derivatives that are exchange traded in active markets for identical assets or liabilities are classified as Level 1. SCE's Level 2 derivatives primarily consist of financial natural gas swaps, fixed float swaps, and natural gas physical trades for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange and Intercontinental Exchange.

Level 3 includes the majority of SCE's derivatives, including over-the-counter options, bilateral contracts, capacity contracts, and QF contracts. The fair value of these SCE derivatives is determined using uncorroborated non-binding broker quotes (from one or more brokers) and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Broker quotes are obtained from several brokers and compared against each other for reasonableness. SCE has Level 3 fixed float swaps for which SCE obtains the applicable Henry Hub and basis forward market prices from the New York Mercantile Exchange. However, these swaps have contract terms that extend beyond observable market data and the unobservable inputs incorporated in the fair value determination are considered significant compared to the overall swap's fair value.

Level 3 also includes derivatives that trade infrequently (such as CRRs in the California market and over-the-counter derivatives at illiquid locations) and long-term power agreements. For illiquid CRRs, SCE reviews objective criteria related to system congestion and other underlying drivers and adjusts fair value when SCE concludes a change in objective criteria would result in a new valuation that better reflects the fair value.

Changes in fair values are based on the hypothetical sale of illiquid positions. For illiquid long-term power agreements, fair value is based upon a discounting of future electricity and natural gas prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit risk and market liquidity. Changes in fair value are based on changes to forward market prices, including forecasted prices for illiquid forward periods. In circumstances where SCE cannot verify fair value with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. As markets continue to develop and more pricing information becomes available, SCE continues to assess valuation methodologies used to determine fair value.

Derivatives with counterparties that have significant nonperformance risk are classified as Level 3. In assessing nonperformance risks, SCE reviews credit ratings of counterparties (and related default rates based on such credit ratings). The fair value of derivative assets and derivative liabilities nonperformance risks was $2 million and $7 million, respectively at December 31, 2009.

Investments in money market funds are generally classified as Level 1 as fair value is determined by observable market prices (unadjusted) in active markets.

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

The following table sets forth assets and liabilities that were accounted for at fair value as of December 31, 2009 by level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$ 360	$ —	$ —	$ —	$ 360
Derivative contracts	—	10	337	—	347
Long-term disability plan	8	—	—	—	8
Nuclear decommissioning trusts[3]					
Stocks[4]	1,772	—	—	—	1,772
Municipal bonds	—	634	—	—	634
Corporate bonds[5]	—	393	—	—	393
U.S. government and agency securities	240	68	—	—	308
Short-term investments, primarily cash equivalents	1	14	—	—	15
Sub-total of nuclear decommissioning trusts	$ 2,013	$ 1,109	$ —	$ —	$ 3,122
Total assets[6]	$ 2,381	$ 1,119	$ 337	$ —	$ 3,837
Liabilities at Fair Value					
Derivative contracts	—	(150)	(448)	—	(598)
Net assets (liabilities)	$ 2,381	$ 969	$ (111)	$ —	$ 3,239

The following table sets forth assets and liabilities that were accounted for at fair value as of December 31, 2008 by level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$ 1,526	$ —	$ —	$ —	$ 1,526
Derivative contracts	2	2	227	—	231
Long-term disability plan	7	—	—	—	7
Nuclear decommissioning trusts[3]					
Stocks[4]	1,308	—	—	—	1,308
Municipal bonds	—	629	—	—	629
U.S. government and agency securities	172	132	—	—	304
Corporate bonds[5]	—	260	—	—	260
Short-term investments, primarily cash equivalents	4	23	—	—	27
Sub-total of nuclear decommissioning trusts	$ 1,484	$ 1,044	$ —	$ —	$ 2,528
Total assets[6]	$ 3,019	$ 1,046	$ 227	$ —	$ 4,292
Liabilities at Fair Value					
Derivative contracts	(2)	(219)	(745)	72	(894)
Net assets (liabilities)	$ 3,017	$ 827	$ (518)	$ 72	$ 3,398

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

2 Included in cash and cash equivalents on SCE's consolidated balance sheet.

3 Excludes net assets/liabilities of $18 million and $(4) million at December 31, 2009 and 2008, respectively, of interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

4 At December 31, 2009 and 2008 respectively, approximately 67% and 68% of the equity investments were located in the United States.

5 Corporate bonds are diversified. At December 31, 2009 and 2008, respectively, this category included $50 million and $72 million for collateralized mortgage obligations and other asset backed securities.

6 Excludes $32 million at both December 31, 2009 and 2008, of cash surrender value of life insurance investments for deferred compensation.

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

	December 31,	
(in millions)	2009	2008
Fair value of derivative contracts, net at beginning of period	$ (518)	$ (22)
Total realized/unrealized losses:		
Included in regulatory assets and liabilities[1]	312	(645)
Purchases and settlements, net	70	167
Transfers in or out of Level 3	25	(18)
Fair value, net at end of period	$ (111)	$ (518)
Change during the period in unrealized gains (losses) related to assets and liabilities held at the end of period	$ 385	$ (573)

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

Nuclear Decommissioning Trusts

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

The following table sets forth amortized cost and fair value of the trust investments:

		December 31,			
		2009	2008	2009	2008
(in millions)		Amortized Cost		Fair Value	
Stocks	–	$ 822	$ 839	$ 1,772	$ 1,308
Municipal bonds	2010 – 2047	545	561	634	629
Corporate bonds	2010 – 2044	309	214	393	260
U.S. government and agency securities	2010 – 2039	287	268	308	304
Short-term investments and receivables/payables	2010	33	24	33	23
Total		$ 1,996	$ 1,906	$ 3,140	$ 2,524

Note: Maturity dates as of December 31, 2009.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Realized gains were $242 million, $201 million and $85 million for the year ended December 31, 2009, 2008 and 2007, respectively. Realized losses were $147 million, $155 million and less than a million for the year ended December 31, 2009, 2008 and 2007, respectively. Proceeds from sales of securities (which are reinvested) were $2.2 billion, $3.1 billion and $3.7 billion for the year ended December 31, 2009, 2008 and 2007, respectively. Unrealized holding gains, net of losses, were $1.1 billion and $618 million at December 31, 2009 and December 31, 2008, respectively. Approximately 92% of the cumulative trust fund contributions were tax-deductible.

The following table sets forth a summary of changes in the fair value of the trust for the year ended December 31, 2009:

(in millions)	2009
Balance at beginning of period	$ 2,524
Realized gains – net	95
Unrealized gains – net	526
Other-than-temporary impairment	(111)
Interest, dividends, contributions and other	106
Balance at end of period	$ 3,140

Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on operating revenue or earnings.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed approximately every three years by the CPUC. These contributions are determined based on an analysis of the liquidation value of the trusts, long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, and after-tax return on trust investments. Favorable or unfavorable investment performance during the intervening period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. On April 3, 2009, SCE submitted its triennial nuclear decommissioning application, requesting that its trust fund contributions increase to approximately $64.5 million per year, beginning on January 1, 2011. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates.

Long-term Debt

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

	December 31,			
	2009		2008	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 6,740	$ 7,202	$ 6,362	$ 6,717

Fair values of long-term debt are based on third-party evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes of new issue prices and relevant credit information.

Note 11. Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded operating revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Under-collections are recorded as regulatory balancing account assets. Over-collections are recorded as regulatory balancing account liabilities. SCE's regulatory balancing accounts accumulate balances until they are refunded to or received from SCE's customers through authorized rate adjustments. Primarily all of SCE's balancing accounts can be classified as one of the following types: generation-revenue related, distribution-revenue related, generation-cost related, distribution-cost related, transmission-cost related or public purpose and other cost related.

Balancing account under-collections and over-collections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts.

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

(in millions)	December 31, 2009	2008
Current:		
Regulatory balancing accounts	$ 94	$ 455
Energy derivatives	25	138
Other	1	12
	$ 120	$ 605
Long-term:		
Regulatory balancing accounts	$ 43	$ 29
Deferred income taxes – net	1,561	1,337
ARO	—	224
Unamortized nuclear investment – net	340	375
Nuclear-related ARO investment – net	258	278
Unamortized coal plant investment – net	73	79
Unamortized loss on reacquired debt	287	309
Pensions and other postretirement benefits	1,014	1,882
Energy derivatives	357	723
Environmental remediation	36	40
Other	170	138
	$ 4,139	$ 5,414
Total Regulatory Assets	$ 4,259	$ 6,019

SCE's regulatory asset related to energy derivatives is primarily an offset to unrealized losses on recorded derivatives. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to income taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory asset related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's nuclear-related regulatory assets related to San Onofre are expected to be recovered by 2022. SCE's nuclear-related regulatory assets related to Palo Verde are expected to be recovered by 2027. SCE's net regulatory asset related to its unamortized coal plant investment is being recovered through June 2016. Although SCE's unamortized nuclear and coal plant investments are classified as regulatory assets on the consolidated balance sheets, they continue to be a component of rate base and earned an 8.75% return in both 2009 and 2008. SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 29 years. SCE's regulatory asset related to pensions and other post-retirement plans represents the recoverable portion of the additional amounts recorded in accordance with authoritative guidance on accounting for pensions and post-retirement plans (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be recovered through rates charged to customers. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

(in millions)	December 31, 2009	December 31, 2008
Current:		
Regulatory balancing accounts	$ 363	$ 1,068
Other	4	43
	$ 367	$ 1,111
Long-term:		
Regulatory balancing accounts	$ 642	$ 43
ARO	171	—
Costs of removal	2,515	2,368
Employee benefit plans	—	70
	$ 3,328	$ 2,481
Total Regulatory Liabilities	$ 3,695	$ 3,592

SCE's regulatory liability related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent operating revenue collected for asset removal costs that SCE expects to incur in the future. SCE's regulatory liabilities related to employee benefit plan expenses represent pension costs recovered through rates charged to customers in excess of the amounts recognized as expense or the difference between these costs calculated in accordance with rate-making methods and these costs calculated in accordance with authoritative guidance on employers accounting for pensions, and PBOP costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will be returned to ratepayers in some future rate-making proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process, or be applied as otherwise directed by the CPUC.

Note 12. Other Income and Expenses

Other income and expenses are as follows:

(in millions)	Years ended December 31, 2009	2008	2007
AFUDC	$ 116	$ 54	$ 46
Increase in cash surrender value of life insurance policies	23	24	23
Energy settlement	9	3	4
Other	12	20	16
Total other income	$ 160	$ 101	$ 89
Various penalties	$ —	$ 59	$ 5
Civic, political and related activities and donations	28	34	25
Other	21	30	15
Total other expenses	$ 49	$ 123	$ 45

Note 13. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's proportionate share of expenses for each project is included in the consolidated statements of income.

The following is SCE's investment in each project as of December 31, 2009:

(in millions)	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 73	$ 13	60%
Pacific Intertie	182	62	50%
Generating stations:			
Four Corners Units 4 and 5 (coal)	580	477	48%
Mohave (coal)	351	303	56%
Palo Verde (nuclear)	1,858	1,527	16%
San Onofre (nuclear)	5,131	4,075	78%
Total	$ 8,175	$ 6,457	

All of Mohave and a portion of San Onofre and Palo Verde are included in regulatory assets on the consolidated balance sheets – see Note 11. Mohave ceased operations on December 31, 2005. In December 2006, SCE acquired the City of Anaheim's approximately 3% ownership interest of San Onofre Units 2 and 3.

Note 14. Variable Interest Entities

As of December 31, 2009, the FASB authoritative guidance defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. This guidance identifies the primary beneficiary as the variable interest holder that absorbs a majority of expected losses; if no variable interest holder meets this criterion, then it is the variable interest holder that receives a majority of the expected residual returns. The primary beneficiary is required to consolidate the variable interest entity unless specific exceptions or exclusions are met. SCE uses variable interest entities to conduct its business as described below.

Projects or Entities that are Consolidated

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by a related party, EME. SCE has determined that it is the primary beneficiary of these four variable interest entities and therefore consolidates these projects.

In determining that SCE was the primary beneficiary, SCE considered the term of the contract, percentage of plant capacity, pricing, and other variable interests. SCE performed a quantitative assessment which included the analysis of the expected losses and expected residual returns of the entity by using the various estimated projected cash flow scenarios associated with the assets and activities of that entity. The quantitative analysis provided sufficient evidence to determine that SCE was the primary beneficiary absorbing a majority of the entity's expected losses, receiving a majority of the entity's expected residual returns, or both.

Project	Capacity	Termination Date[1]	EME Ownership
Kern River	300 MW	June 2011	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

1 As mandated by the CPUC, Midway-Sunset, Sycamore Cogeneration and Watson sell electricity to SCE under an extension of their prior power purchase agreements, with revised pricing. On September 28, 2009, Midway-Sunset entered into a power purchase agreement with PG&E, that expires in 2016, for which CPUC approval is pending. Sycamore Cogeneration entered into a new steam supply agreement with Chevron North America Exploration and Production Company that expires in 2013.

These four projects do not have any third party debt outstanding. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any profit or loss generated by these entities will not affect SCE's income statement. Any liabilities of these projects are nonrecourse to SCE. See Note 16 for carrying value and classification of the VIEs' assets and liabilities.

Entities with Unavailable Financial Information

SCE also has seven other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under this standard and continues to attempt to obtain information for these projects in order to determine whether the projects should be consolidated. These entities are not legally obligated to provide financial information to SCE and have declined to do so. Because these potential VIEs were created prior to December 31, 2003, SCE is not required to apply this accounting guidance to these entities as long as SCE continues to be unable to obtain this information. The aggregate capacity dedicated to SCE for these projects was 263 MW at both December 31, 2009 and December 31, 2008. The amounts that SCE paid to these projects were $129 million, $203 million and $180 million for 2009, 2008 and 2007, respectively. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

Note 15. Preferred and Preference Stock Not Subject to Mandatory Redemption

SCE's authorized shares are: $100 cumulative preferred – 12 million shares, $25 cumulative preferred – 24 million shares and preference with no par value – 50 million shares. There are no dividends in arrears for the preferred stock or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the years ended December 31, 2009 and 2008. In January 2008, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. There is no sinking fund requirement for redemptions or repurchases of preferred stock.

Shares of SCE's preference stock rank junior to all of the preferred stock and senior to all common stock. Shares of SCE's preference stock are not convertible into shares of any other class or series of SCE's capital stock or any other security. The preference shares are noncumulative and have a $100 liquidation value. There is no sinking fund for the redemption or repurchase of the preference shares.

Preferred stock and preference stock not subject to mandatory redemption is:

(in millions, except per-share amounts)	Shares Outstanding	Redemption Price	December 31, 2009	December 31, 2008
Cumulative preferred stock				
$25 par value:				
4.08% Series	650,000	$ 25.50	$ 16	$ 16
4.24% Series	1,200,000	25.80	30	30
4.32% Series	1,653,429	28.75	41	41
4.78% Series	1,296,769	25.80	33	33
Preference stock				
No par value:				
5.349% Series A	4,000,000	$ 100.00	400	400
6.125% Series B	2,000,000	100.00	200	200
6.00% Series C	2,000,000	100.00	200	200
			$ 920	$ 920

The Series A preference stock, issued in 2005, may not be redeemed prior to April 30, 2010. After April 30, 2010, SCE may, at its option, redeem the shares in whole or in part and the dividend rate may be adjusted. The Series B preference stock, issued in 2005, may not be redeemed prior to September 30, 2010. After September 30, 2010, SCE may, at its option, redeem the shares in whole or in part. The Series C preference stock, issued in 2006, may not be redeemed prior to January 31, 2011. After January 31, 2011, SCE may, at its option, redeem the shares in whole or in part. No preference stock not subject to mandatory redemption was redeemed in the last three years.

Note 16. Business Segments

SCE's reportable business segments include the rate-regulated electric utility segment and the VIEs segment. The VIEs are gas-fired power plants that sell both electricity and steam. The VIE segment consists of non-rate-regulated entities (all in California). SCE's management has no control over the resources allocated to the VIE segment and does not make decisions about its performance. Additional details on the VIE segment are shown in Note 14.

SCE's consolidated balance sheet captions impacted by VIE activities are presented below:

(in millions)	Electric Utility	VIEs	Eliminations	SCE
	December 31, 2009			
Cash and equivalents	$ 370	$ 92	$ —	$ 462
Accounts receivable – net	689	62	(32)	719
Inventory	321	16	—	337
Other current assets	94	3	—	97
Nonutility property – net of accumulated depreciation	71	253	—	324
Other long-term assets	318	4	—	322
Total assets	$ 32,076	$ 430	$ (32)	$ 32,474
Accounts payable	1,031	59	(32)	1,058
Other current liabilities	632	5	—	637
Asset retirement obligations	3,181	17	—	3,198
Noncontrolling interest	—	349	—	349
Total liabilities and equity	$ 32,076	$ 430	$ (32)	$ 32,474
	December 31, 2008			
Cash and equivalents	$ 1,522	$ 89	$ —	$ 1,611
Accounts receivable – net	679	63	(39)	703
Inventory	346	19	—	365
Other current assets	279	4	—	283
Nonutility property – net of accumulated depreciation	671	282	—	953
Other long-term assets	363	1	—	364
Total assets	$ 32,149	$ 458	$ (39)	$ 32,568
Accounts payable	926	61	(39)	948
Other current liabilities	570	2	—	572
Asset retirement obligations	2,992	15	—	3,007
Noncontrolling interest	—	380	—	380
Total liabilities and equity	$ 32,149	$ 458	$ (39)	$ 32,568

SCE's consolidated statements of income, by business segment, are presented below:

(in millions)	Electric Utility	VIEs	Eliminations[1]	SCE
	Year Ended December 31, 2009			
Operating revenue	$ 9,746	$ 589	$ (370)	$ 9,965
Fuel	353	368	—	721
Purchased power	3,121	—	(370)	2,751
Operation and maintenance	3,060	94	—	3,154
Depreciation, decommissioning and amortization	1,145	33	—	1,178
Property and other taxes	244	—	—	244
Gain on sale of assets	(1)	—	—	(1)
Total operating expenses	7,922	495	(370)	8,047
Operating income	1,824	94	—	1,918
Interest income	11	—	—	11
Other income	160	—	—	160
Interest expense – net of amounts capitalized	(420)	—	—	(420)
Other expenses	(49)	—	—	(49)
Income before income taxes	1,526	94	—	1,620
Income tax expense	(249)	—	—	(249)
Net income	1,277	94	—	1,371
Less: Net income attributable to noncontrolling interest	—	(94)	—	(94)
Dividends on preferred and preference stock not subject to mandatory redemption	(51)	—	—	(51)
Net income available for common stock	$ 1,226	$ —	$ —	$ 1,226
	Year Ended December 31, 2008			
Operating revenue	$ 10,838	$ 1,102	$ (692)	$ 11,248
Fuel	587	813	—	1,400
Purchased power	4,537	—	(692)	3,845
Operation and maintenance	2,923	90	—	3,013
Depreciation, decommissioning and amortization	1,080	34	—	1,114
Property and other taxes	232	—	—	232
Gain on sale of asset	(9)	—	—	(9)
Total operating expenses	9,350	937	(692)	9,595
Operating income	1,488	165	—	1,653
Interest income	19	3	—	22
Other income	99	2	—	101
Interest expense – net of amounts capitalized	(407)	—	—	(407)
Other expenses	(123)	—	—	(123)
Income before income taxes	1,076	170	—	1,246
Income tax expense	(342)	—	—	(342)
Net income	734	170	—	904
Less: Net income attributable to noncontrolling interest	—	(170)	—	(170)
Dividends on preferred and preference stock not subject to mandatory redemption	(51)	—	—	(51)
Net income available for common stock	$ 683	$ —	$ —	$ 683

	Year Ended December 31, 2007			
Operating revenue	$ 9,854	$ 1,129	$ (750)	$ 10,233
Fuel	482	709	—	1,191
Purchased power	3,985	—	(750)	3,235
Operation and maintenance	2,742	96	—	2,838
Depreciation, decommissioning and amortization	975	36	—	1,011
Property and other taxes	217	—	—	217
Total operating expenses	8,401	841	(750)	8,492
Operating income	1,453	288	—	1,741
Interest income	41	3	—	44
Other income	75	14	—	89
Interest expense – net of amounts capitalized	(429)	—	—	(429)
Other expenses	(45)	—	—	(45)
Income before income taxes	1,095	305	—	1,400
Income tax expense	(337)	—	—	(337)
Net income	758	305	—	1,063
Less: Net income attributable to noncontrolling interest	—	(305)	—	(305)
Dividends on preferred and preference stock not subject to mandatory redemption	(51)	—	—	(51)
Net income available for common stock	$ 707	$ —	$ —	$ 707

1 VIE segment operating revenue includes sales to the electric utility segment, which are eliminated in operating revenue and purchased power in the consolidated statements of income.

Note 17. Quarterly Financial Data (Unaudited)

(in millions)	Total	Fourth	Third	Second	First
			2009		
Operating revenue	$ 9,965	$ 2,434	$ 3,069	$ 2,273	$ 2,189
Operating income	1,918	361	696	423	441
Net income	1,371	189	415	534	233
Net income available for common stock	1,226	172	346	499	208
Common dividends declared	300	100	100	100	—
			2008		
Operating revenue	$ 11,248	$ 2,551	$ 3,468	$ 2,850	$ 2,379
Operating income	1,653	316	663	331	345
Net income	904	163	342	221	179
Net income available for common stock	683	141	235	157	150
Common dividends declared	400	100	100	100	100

Due to the seasonal nature of SCE's business, a significant amount of revenue and earnings are recorded in the third quarter of each year. As a result of rounding, the total of the four quarters does not always equal the amount for the year. In 2009, SCE recorded a benefit of $306 million, after tax, related to the Global Settlement.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SCE's management, under the supervision and with the participation of the company's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of SCE's disclosure controls and procedures (as that term is defined in Rules 13a-15(e) or 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period, SCE's disclosure and procedures are effective.

SCE's management is responsible for establishing and maintaining adequate internal control over financial reporting (as that term is defined in Rule 13a-15(f) under the Exchange Act) for SCE. Under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, SCE's management conducted an evaluation of the effectiveness of SCE's internal control over financial reporting based on the framework set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on its evaluation under the COSO framework, SCE's management concluded that SCE's internal control over financial reporting was effective as of December 31, 2009.

Change in Internal Control Over Financial Reporting

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

Variable Interest Entities

SCE consolidates four variable interest entities under authoritative accounting guidance issued by the FASB, but does not control the operating activities of these entities or have the ability to dictate or modify the controls of these entities. Accordingly, the scope of evaluation of internal control over financial reporting does not include an evaluation of internal control over financial reporting for these variable interest entities. A summary of the key sub-totals of these entities is set forth in the following table (in millions):

	2009
At December 31,	
Total Assets	$ 398
For the year ended December 31,	
Revenue	$ 219
Operating Expenses	$ 125
Net Income Available for Common Stock	$ —

Accordingly, the conclusion regarding the effectiveness of internal control over financial reporting does not extend to the internal controls of such variable interest entities.

Jointly Owned Utility Plant

SCE's scope of evaluation of internal control over financial reporting includes its Jointly Owned Utility Projects.

Management's Report on Internal Control Over Financial Reporting

SCE's management is responsible for establishing and maintaining adequate internal control over financial reporting (as that term is defined in Rule 13a-15(f) under the Exchange Act) for SCE. Under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, SCE's management conducted an evaluation of the effectiveness of SCE's internal control over financial reporting based on the framework set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on its evaluation under the COSO framework, SCE's management concluded that SCE's internal control over financial reporting was effective as of December 31, 2009.

ITEM 9A(T). CONTROLS AND PROCEDURES

This Annual Report on Form 10-K does not include an attestation report of SCE's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by SCE's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit SCE to provide only management's report in this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

On February 25, 2010, the Board of Directors of SCE elected Chris Dominski to serve as Controller of SCE, effective March 2, 2010. Ms. Dominski, age 43, has been employed as Assistant Controller of Edison International and SCE since March 2007. She previously held managerial positions in SCE's Regulatory Policy and Affairs (from January 2000 to July 2006) and Treasurer's (from July 2006 to February 2007) Departments.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning executive officers of SCE is set forth in Part I in accordance with General Instruction G(3), pursuant to Instruction 3 to Item 401(b) of Regulation S-K. Other information responding to Item 10 will appear in SCE's definitive Proxy Statement to be filed with the SEC in connection with SCE's Annual Shareholders' Meeting to be held on April 22, 2010, under the headings "Item 1: Election of Directors," "Board Committees," and "Corporate Governance–Q: Which Director nominees has the Board determined are independent?" and is incorporated herein by this reference.

The Edison International Ethics and Compliance Code is applicable to all Directors, officers and employees of Edison International and its majority-owned subsidiaries, including SCE. The Code is available on Edison International's Internet website at www.edisonethics.com and is available in print without charge upon request from the SCE Corporate Secretary. Any amendments or waivers of Code provisions for SCE's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, will be posted on Edison International's Internet website at www.edisonethics.com.

ITEM 11. EXECUTIVE COMPENSATION

Information responding to Item 11 will appear in the Proxy Statement under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Compensation Committee Interlocks and Insider Participation," "Summary Compensation Table," "Grants of Plan-Based Awards," "Outstanding Equity Awards at Fiscal Year-End," "Option Exercises and Stock Vested," "Pension Benefits," "Non-qualified Deferred Compensation," "Potential Payments Upon Termination or Change in Control," and "Director Compensation," and is incorporated herein by this reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information responding to Item 12 will appear in the Proxy Statement under the headings "Stock Ownership of Director Nominees and Executive Officers" and "Stock Ownership of Certain Shareholders," and is incorporated herein by this reference.

Item 201(d) of Regulation S-K, "Securities Authorized For Issuance Under Equity Compensation Plans," is not applicable because SCE has no compensation plans under which equity securities of SCE are authorized for issuance.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information responding to Item 13 will appear in the Proxy Statement under the headings "Certain Relationships and Related Transactions," and "Corporate Governance–Q: Is SCE subject to the same stock exchange listing standards as EIX?,–Q: How does the Board determine which Directors are considered independent?–Q: Which Director nominees has the Board determined are independent?" and "Where can I find the Company's corporate governance documents?" and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information responding to Item 14 will appear in the Proxy Statement under the heading "Independent Registered Public Accounting Firm Fees," and is incorporated herein by this reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

See Index to Consolidated Financial Statements in Item 8 of this report.

(a)(2) Report of Independent Registered Public Accounting Firm and Schedules Supplementing Financial Statements

Schedules I and III through V, inclusive, are omitted as not required or not applicable.

(a)(3) Exhibits

See Exhibit Index beginning on page 137 of this report.

SCE will furnish a copy of any exhibit listed in the accompanying Exhibit Index upon written request and upon payment to SCE of its reasonable expenses of furnishing such exhibit, which shall be limited to photocopying charges and, if mailed to the requesting party, the cost of first-class postage.

Report of Independent Registered Public Accounting Firm on Financial Statement Schedule

To the Board of Directors
of Southern California Edison Company

Our audits of the consolidated financial statements referred to in our report dated March 1, 2010 appearing in the 2009 Annual Report to Shareholder of Southern California Edison Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

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

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
For the Year Ended December 31, 2009

(in millions)	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Uncollectible accounts					
Customers	$ 28.4	$ 28.7	$ —	$ 23.2	$ 33.9
All other	10.3	20.6	—	11.9	19.0
Total	$ 38.7	$ 49.3	$ —	$ 35.1[(a)]	$ 52.9

(a) Accounts written off, net.

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
For the Year Ended December 31, 2008

(in millions)	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Uncollectible accounts					
Customers	$ 20.6	$ 28.7	$ —	$ 20.9	$ 28.4
All other	13.9	8.2	—	11.8	10.3
Total	$ 34.5	$ 36.9	$ —	$ 32.7[a]	$ 38.7

[a] Accounts written off, net.

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
For the Year Ended December 31, 2007

(in millions)	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Uncollectible accounts					
Customers	$ 18.4	$ 19.5	$ —	$ 17.3	$ 20.6
All other	10.1	9.0	—	5.2	13.9
Total	$ 28.5	$ 28.5	$ —	$ 22.5[a]	$ 34.5

[a] Accounts written off, net.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Linda G. Sullivan

LINDA G. SULLIVAN
Senior Vice President, Chief Financial Officer And Acting Controller

Date: March 1, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title
Principal Executive Officer:	
Alan J. Fohrer*	Chairman of the Board and Chief Executive Officer
Principal Financial Officer:	
Linda G. Sullivan*	Senior Vice President and Chief Financial Officer and Acting Controller
Board of Directors:	
Vanessa C.L. Chang*	Director
France A. Córdova*	Director
Theodore F. Craver, Jr.	Director
Charles B. Curtis*	Director
Alan J. Fohrer	Director
Bradford M. Freeman*	Director
Luis G. Nogales*	Director
Ronald L. Olson*	Director
James M. Rosser*	Director
Richard T. Schlosberg, III*	Director
Thomas C. Sutton*	Director
Brett White*	Director

*By: /s/ Linda G. Sullivan

LINDA G. SULLIVAN
Senior Vice President, Chief Financial Officer
and Acting Controller

Date: March 1, 2010

EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Restated Articles of Incorporation of Southern California Edison Company, effective March 2, 2006 (File No. 1-2213, filed as Exhibit 3.1 to Southern California Edison Company's Form 10-K for the year ended December 31 2005)*
3.2	Amended Bylaws of Southern California Edison Company, as Adopted by the Board of Directors effective December 11, 2008 (File No. 1-9936, filed as Exhibit 3.2 to Edison International's Form 10-K for the year ended December 31, 2008)*
4.1	Senior Indenture, dated September 28, 1999 (File No. 1-9936, filed as Exhibit 4.1 to Edison International's Form 10-Q for the quarter ended September 30, 1999)*
4.2	Southern California Edison Company First Mortgage Bond Trust Indenture, dated as of October 1, 1923 (Registration No. 2-1369)*
4.3	Supplemental Indenture, dated as of March 1, 1927 (Registration No. 2-1369)*
4.4	Third Supplemental Indenture, dated as of June 24, 1935 (Registration No. 2-1602)*
4.5	Fourth Supplemental Indenture, dated as of September 1, 1935 (Registration No. 2-4522)*
4.6	Fifth Supplemental Indenture, dated as of August 15, 1939 (Registration No. 2-4522)*
4.7	Sixth Supplemental Indenture, dated as of September 1, 1940 (Registration No. 2-4522)*
4.8	Eighth Supplemental Indenture, dated as of August 15, 1948 (Registration No. 2-7610)*
4.9	Twenty-Fourth Supplemental Indenture, dated as of February 15, 1964 (Registration No. 2-22056)*
4.10	Eighty-Eighth Supplemental Indenture, dated as of July 15, 1992 (File No. 1-2313, Form 8-K dated July 22, 1992)*
4.11	Indenture, dated as of January 15, 1993 (File No. 1-2313, Form 8-K dated January 28, 1993)*
10.1**	Form of 1981 Deferred Compensation Agreement (File No. 1-2313, filed as Exhibit 10.2 to Southern California Edison Company's Form 10-K for the year ended December 31, 1981)*
10.2**	Form of 1985 Deferred Compensation Agreement for Directors (File No. 1-2313, filed as Exhibit 10.4 to Southern California Edison Company's Form 10-K for the year ended December 31, 1985)*

Exhibit Number	Description
10.3**	Form of 1985 Deferred Compensation Agreement for Directors (File No. 1-2313, filed as Exhibit 10.4 to Southern California Edison Company's Form 10-K for the year ended December 31, 1985)*
10.3.1**	Amendment to 1985 Deferred Compensation Plan Agreement for Directors with James M. Rosser, dated December 31, 2003 (File No. 1-2313, filed as Exhibit 10.36 to Southern California Edison Company's Form 10-K for the year ended December 31, 2003)*
10.4**	Director Deferred Compensation Plan as amended December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.4 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.5**	2008 Director Deferred Compensation Plan, effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.5 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.6**	Director Grantor Trust Agreement, dated August 1995 (File No. 1-9936, filed as Exhibit 10.10 to Edison International's Form 10-K for the year ended December 31, 1995)*
10.6.1**	Director Grantor Trust Agreement Amendment 2002-1, effective May 14, 2002 (File No. 1-9936, filed as Exhibit 10.4 to Edison International's Form 10-Q for the quarter ended June 30, 2002)*
10.6.2**	Executive and Director Grantor Trust Agreements Amendment 2008-1 (File No. 1-9936, filed as Exhibit No. 10.6.2 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.7**	Executive Deferred Compensation Plan, as amended and restated December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.7 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.8**	2008 Executive Deferred Compensation Plan, effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.8 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.9**	Executive Grantor Trust Agreement, dated August 1995 (File No. 1-9936, filed as Exhibit 10.12 to Edison International's Form 10-K for the year ended December 31, 1995)*
10.9.1**	Executive Grantor Trust Agreement Amendment 2002-1, effective May 14, 2002 (File No. 1-9936, filed as Exhibit 10.3 to Edison International's Form 10-Q for the quarter ended June 30, 2002)*
10.10**	Executive Supplemental Benefit Program, as amended December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.10 to Edison International's Form 10-K for the year ended December 31, 2008)*

Exhibit Number	Description
10.11**	Dispute resolution amendment, adopted November 30, 1989 of 1981 Executive Deferred Compensation Plan and 1985 Executive and Director Deferred Compensation Plans (File No. 1-9936, filed as Exhibit 10.21 to Edison International's Form 10-K for the year ended December 31, 1998)*
10.12**	Executive Retirement Plan as restated effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.12 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.13**	2008 Executive Retirement Plan effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.13 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.14**	Edison International Executive Incentive Compensation Plan, as amended in February 2009 (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended June 30, 2009)*
10.15**	2008 Executive Disability Plan, effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.15 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.16**	2008 Executive Survivor Benefit Plan, effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.16 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.17**	Retirement Plan for Directors, as amended and restated effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.17 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.18**	Equity Compensation Plan as restated effective January 1, 1998 (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended June 30, 1998)*
10.18.1**	Equity Compensation Plan Amendment No. 1, effective May 18, 2000 (File No. 1-9936, filed as Exhibit 10.4 to Edison International's Form 10-Q for the quarter ended June 30, 2000)*
10.18.2**	Amendment of Equity Compensation Plans, adopted October 25, 2006 (File No. 1-9936, filed as Exhibit 10.52 to Edison International's Form 10-K for the year ended December 31, 2006)*
10.19**	2000 Equity Plan, effective May 18, 2000 (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended June 30, 2000)*
10.20**	Edison International 2007 Performance Incentive Plan, as amended and restated in February 2009 (File No. 1-9936, filed as Exhibit 10.3 to the Edison International's Form 10-Q for the quarter ended June 30, 2009)*
10.20.1**	Edison International 2009 Long-Term Incentives Terms and Conditions (File No. 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended March 31, 2009)*

Exhibit Number	Description
10.21**	Terms and conditions for 1999 long-term compensation awards under the Equity Compensation Plan (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended March 31, 1999)*
10.21.1**	Terms and conditions for 2000 basic long-term incentive compensation awards under the Equity Compensation Plan, as restated (File No. 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended March 31, 2000)*
10.21.2**	Terms and conditions for 2000 special stock option awards under the Equity Compensation Plan and 2000 Equity Plan (File No. 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended June 30, 2000)*
10.21.3**	Terms and conditions for 2002 long-term compensation awards under the Equity Compensation Plan and 2000 Equity Plan (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended March 31, 2002)*
10.21.4**	Terms and conditions for 2003 long-term compensation awards under the Equity Compensation Plan and 2000 Equity Plan (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended March 31, 2003)*
10.21.5**	Terms and conditions for 2004 long-term compensation awards under the Equity Compensation Plan and 2000 Equity Plan (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended March 31, 2004)*
10.21.6**	Terms and conditions for 2005 long-term compensation award under the Equity Compensation Plan and 2000 Equity Plan (File No. 1-9936, filed as Exhibit 99.2 to Edison International's Form 8-K dated December 16, 2004 and filed on December 22, 2004)*
10.21.7**	Terms and conditions for 2006 long-term compensation awards under the Equity Compensation Plan and 2000 Equity Plan (File No. 1-9936, filed as Exhibit 10.29 to Edison International's Form 10-K for the year ended December 31, 2005)*
10.21.8**	Terms and conditions for 2007 long-term compensation awards under the Equity Compensation Plan and 2000 Equity Plan (File No. 1-9936, filed as Exhibit 99.1 to Edison International's Form 8-K dated February 22, 2007 and filed on February 26, 2007)*
10.21.9**	Terms and conditions for 2007 long-term compensation awards under the Equity Compensation Plan and the 2007 Performance Incentive Plan (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended March 31, 2007)*
10.22**	Director Nonqualified Stock Option Terms and Conditions under the Equity Compensation Plan (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended June 30, 2002)*
10.22.1**	Director 2004 Nonqualified Stock Option Terms and Conditions under the Equity Compensation Plan (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended June 30, 2004)*

Exhibit Number	Description
10.22.2*	Director Nonqualified Stock Option Terms and Conditions under the 2007 Performance Incentive Plan (File 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended March 31, 2007)*
10.23**	Edison International and Edison Capital Affiliate Option Exchange Offer Circular, dated July 3, 2000 (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended September 30, 2000)*
10.23.1**	Edison International and Edison Capital Affiliate Option Exchange Offer Summary of Deferred Compensation Alternatives, dated July 3, 2000 (File No. 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended September 30, 2000)*
10.23.2**	Edison International and Edison Mission Energy Affiliate Option Exchange Offer Circular, dated July 3, 2000 (File No. 1-13434, filed as Exhibit 10.93 to the Edison Mission Energy's Form 10-K for the year ended December 31, 2001)*
10.23.3**	Edison International and Edison Mission Energy Affiliate Option Exchange Offer Summary of Deferred Compensation Alternatives, dated July 3, 2000 (File No. 1-13434, filed as Exhibit 10.94 to the Edison Mission Energy's Form 10-K for the year ended December 31, 2001)*
10.24**	Estate and Financial Planning Program as amended December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.24 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.25**	Resolution regarding the computation of disability and survivor benefits prior to age 55 for Alan J. Fohrer dated February 17, 2000 (File No. 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended March 31, 2000)*
10.26**	2008 Executive Severance Plan, as amended and restated effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.26 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.27**	Director Deferred Compensation Plan Authorization of Edison International (File No. 1-9936, filed in Edison International's Form 8-K dated December 30, 2004, and filed on January 5, 2005)*
10.28**	2008 Director Deferred Compensation Plan, effective December 31, 2008 (File No. 1-9936, filed as Exhibit No. 10.28 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.29**	Edison International Director Compensation Schedule, as adopted June 18, 2009 (File No. 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended June 30, 2009)*
10.30**	Edison International Director Matching Gifts Program, as adopted June 29, 2007 (File No. 1-9936, filed as Exhibit 10.2 to Edison International's Form 10-Q for the quarter ended June 30, 2007)*

Exhibit Number	Description
10.31**	Edison International Director Nonqualified Stock Options 2005 Terms and Conditions (File No. 1-9936, filed as Exhibit 99.3 to Edison International's Form 8-K dated May 19, 2005, and filed on May 25, 2005)*
10.32	Amended and Restated Agreement for the Allocation of Income Tax Liabilities and Benefits among Edison International, Southern California Edison Company and The Mission Group dated September 10, 1996 (File No. 1-9936, filed as Exhibit 10.3 to Edison International's Form 10-Q for the quarter ended September 30, 2002)*
10.32.1	Amended and Restated Tax Allocation Agreement among The Mission Group and its first-tier subsidiaries dated September 10, 1996 (File No. 1-9936, filed as Exhibit 10.3.1 to Edison International's Form 10-Q for the quarter ended September 30, 2002)*
10.32.2	Amended and Restated Tax Allocation Agreement between Edison Capital and Edison Funding Company (formerly Mission First Financial and Mission Funding Company) dated May 1, 1995 (File No. 1-9936, filed as Exhibit 10.3.2 to Edison International's Form 10-Q for the quarter ended September 30, 2002)*
10.32.3	Tax Allocation Agreement between Mission Energy Holding Company and Edison Mission Energy dated July 2, 2001 (File No. 1-9936, filed as Exhibit 10.3.3 to Edison International's Form 10-Q for the quarter ended September 30, 2002)*
10.32.4	Administrative Agreement re Tax Allocation Payments among Edison International, Southern California Edison Company, The Mission Group, Edison Capital, Mission Energy Holding Company, Edison Mission Energy, Edison O&M Services, Edison Enterprises, and Mission Land Company dated July 2, 2001 (File No. 1-9936, filed as Exhibit 10.3.4 to Edison International's Form 10-Q for the quarter ended September 30, 2002)*
10.33**	Form of Indemnity Agreement between Edison International and its Directors and any officer, employee or other agent designated by the Board of Directors (File No. 1-9936, filed as Exhibit 10.5 to Edison International's Form 10-Q for the period ended June 30, 2005, and filed on August 9, 2005)*
10.34**	Edison International 2009 Executive Bonus Program (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended March 31, 2009)*
10.35**	Edison International Executive Perquisites (File No. 1-9936, filed as Exhibit No. 10.36 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.36**	Section 409A and Other Conforming Amendments to Terms and Conditions (File No. 1-9936, filed as Exhibit No. 10.37 to Edison International's Form 10-K for the year ended December 31, 2008)*

Exhibit Number	Description
10.36.1**	Section 409A Amendments to Director Terms and Conditions (File No. 1-9936, filed as Exhibit No. 10.37.1 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.37**	Consulting Arrangement with John E. Bryson (File No. 1-9936, filed as Exhibit 10.38 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.38	Amended and Restated Credit Agreement, dated as of February 23, 2007, among Southern California Edison Company and JP Morgan Chase Bank, N.A., as Administrative Agent, Citicorp North America, Inc., as Syndication Agent, Credit Suisse, Lehman Commercial Paper Inc., and Wells Fargo Bank, N.A., as Documentation Agents, and the lenders thereto (File No. 1-2313, filed as Exhibit 10.1 to Southern California Edison Company's Form 8-K dated and filed February 27, 2007)*
10.39	First Amendment to Amended and Restated Credit Agreement, dated as of February 14, 2008 (File No. 1-2313, filed as Exhibit 10.1 to Southern California Edison Company's Form 8-K dated and filed March 19, 2008)*
10.40	Second Amendment to Amended and Restated Credit Agreement, dated as of December 19, 2008 (File No. 1-9936, filed as Exhibit 10.41 to Edison International's Form 10-K for the year ended December 31, 2008)*
10.41	Credit Agreement, dated as of March 17, 2009, among Southern California Edison Company and Bank of America, N.A., as Administrative Agent, Wells Fargo Bank, N.A. as Syndication Agent, and Barclays Bank PLC, Morgan Stanley Bank, N.A. Sun Trust Bank and UBS Loan Finance LLC, as Documentation Agents, and the lenders thereto (File No. 1-2323, filed as Exhibit 10 to Southern California Edison Company's Form 8-K dated March 17, 2009)*
12	Computation of Ratios of Earnings to Fixed Charges
23	Consent of Independent Registered Public Accounting Firm
24.1	Power of Attorney
24.2	Certified copy of Resolution of Board of Directors Authorizing Signature
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act

Exhibit Number	Description
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
32	Statement Pursuant to 18 U.S.C. Section 1350
101***	Financial statements from the annual report on Form 10-K of Southern California Edison Company for the year ended December 31, 2009, filed on March 1, 2010, formatted in XBRL: (i) the Consolidated Statements of Income; (ii) the Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Cash Flows; (v) Consolidated Statements of Changes in Equity and (vi) the Notes to Consolidated Financial Statements tagged as blocks of text

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

** Indicates a management contract or compensatory plan or arrangement, as required by Item 15(a)3.

*** Furnished, not filed, pursuant to Rule 406T of SEC Regulation S-T.

Board of Directors

Alan J. Fohrer[3]
Chairman of the Board and
Chief Executive Officer,
Southern California Edison
A director since 2002

Vanessa C.L. Chang[1,4]
Principal,
EL & EL Investments
(private real estate investment company)
Los Angeles, California
A director since 2007

France A. Córdova[4,5]
President,
Purdue University
West Lafayette, Indiana
A director since 2004

Charles B. Curtis[4,5]
President Emeritus,
Nuclear Threat Initiative
(private foundation dealing with
national security issues)
Washington, DC
A director since 2006

Bradford M. Freeman[1,2,3]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Luis G. Nogales[1,4]
Managing Partner,
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

Ronald L. Olson[3,4]
Senior Partner,
Munger, Tolles & Olson (law firm)
Los Angeles, California
A director since 1995

James M. Rosser[2,3,5]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1988

Richard T. Schlosberg, III[1,2,5]
Retired President and
Chief Executive Officer,
The David and Lucile Packard Foundation
(private family foundation)
San Antonio, Texas
A director since 2002

Thomas C. Sutton[1,2,3]
Retired Chairman of the Board and
Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

Brett White[2,5]
President and
Chief Executive Officer,
CB Richard Ellis
(commercial real estate services company)
Los Angeles, California
A director since 2007

1 Audit Committee
2 Compensation and Executive Personnel Committee
3 Executive Committee
4 Finance Committee
5 Nominating/Corporate Governance Committee

Management Team

Alan J. Fohrer
Chairman of the Board and
Chief Executive Officer

John R. Fielder
President

Pedro J. Pizarro
Executive Vice President,
Power Operations

Bruce C. Foster
Senior Vice President,
Regulatory Affairs

Stuart R. Hemphill
Senior Vice President,
Power Procurement

Cecil R. House
Senior Vice President,
Safety & Operations Support and
Chief Procurement Officer

James A. Kelly
Senior Vice President,
Transmission and Distribution

Stephen E. Pickett
Senior Vice President and
General Counsel

Ross T. Ridenoure
Senior Vice President and
Chief Nuclear Officer

Linda G. Sullivan
Senior Vice President and
Chief Financial Officer

Mahvash Yazdi
Senior Vice President,
Business Integration and
Chief Information Officer

Lynda L. Ziegler
Senior Vice President,
Customer Service

Robert C. Boada
Vice President and Treasurer

Lisa D. Cagnolatti
Vice President,
Business Customer Division

Kevin R. Cini
Vice President,
Energy Supply and Management

Ann P. Cohn
Vice President and
Associate General Counsel

Paul J. De Martini
Vice President,
Advanced Technology

Chris C. Dominski
Vice President and Controller

Erwin G. Furukawa
Vice President,
Customer Programs and Services

Veronica Gutierrez
Vice President,
Corporate Communications

Harry B. Hutchison
Vice President,
Customer Service Operations

Akbar Jazayeri
Vice President,
Regulatory Operations

Walter J. Johnston
Vice President,
Power Delivery

R. W. (Russ) Krieger, Jr.
Vice President,
Power Production

Barbara E. Mathews
Vice President,
Associate General Counsel,
Chief Governance Officer and
Corporate Secretary

David L. Mead
Vice President,
Engineering and Technical Services

Patricia H. Miller
Vice President,
Human Resources

Stacy R. Mines
Vice President and
Chief Ethics and Compliance Officer

Kevin M. Payne
Vice President,
Business Integration

Megan Scott-Kakures
Vice President and General Auditor

Leslie E. Starck
Vice President,
Local Public Affairs

Russell C. Swartz
Vice President and
Associate General Counsel

Marc L. Ulrich
Vice President,
Renewable & Alternative Power

Gaddi H. Vasquez
Vice President,
Public Affairs

Shareholder Information

Annual Meeting

The annual meeting of shareholders will be held on Thursday, April 22, 2010, at 9:00 a.m., Pacific Time, at the Hilton Los Angeles San Gabriel Hotel, 225 West Valley Boulevard, San Gabriel, California 91776.

Corporate Governance Practices

A description of SCE's corporate governance practices is available on our Web site at www.edisoninvestor.com. The SCE Board Nominating/Corporate Governance Committee periodically reviews the Company's corporate governance practices and makes recommendations to the Company's Board that the practices be updated from time to time.

Stock and Trading Information

Preferred Stock and Preference Stock
SCE's 4.08%, 4.24%, 4.32% and 4.78% Series of $25 par value cumulative preferred stock are listed on the American Stock Exchange. Previous day's closing prices, when stock was traded, are listed in the daily newspapers under the American Stock Exchange. Shares of SCE's Series A, Series B and Series C preference stock are not listed on an exchange.

Transfer Agent and Registrar

Wells Fargo Bank, N.A., which maintains shareholder records, is the transfer agent and registrar for SCE's preferred and preference stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

- stock transfer and name-change requirements;
- address changes, including dividend payment addresses;
- electronic deposit of dividends;
- taxpayer identification number submissions or changes;
- duplicate 1099 and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks; and
- requests for access to online account information.

Inquiries may also be directed to:

Wells Fargo Bank, N.A.
Shareowner Services Department
161 North Concord Exchange Street
South St. Paul, MN 55075-1139

Fax

(651) 450-4033
Wells Fargo Shareowner Services℠
www.wellsfargo.com/shareownerservices

Web Address

www.edisoninvestor.com

Online account information

www.shareowneronline.com

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