SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

2010 ANNUAL REPORT

EDISON INTERNATIONAL
Celebrating 125 Years
1886-2011

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.

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, 2010

☐ **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
Cumulative Preferred Stock	**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 24, 2011, 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 2011 Annual Meeting of Shareholders	Part III

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GLOSSARY

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

2010 Tax Relief Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
AFUDC	allowance for funds used during construction
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	California Air Resources Board
CDWR	California Department of Water Resources
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DOE	U. S. Department of Energy
ERRA	energy resource recovery account
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGIC	Financial Guarantee Insurance Company
FIP(s)	federal implementation plan(s)
Four Corners	coal fueled electric generating facility located in Farmington, New Mexico in which SCE holds a 48% ownership interest
GAAP	generally accepted accounting principles
GHG	greenhouse gas
Global Settlement	A settlement between Edison International and the IRS that resolves all of SCE's federal income tax disputes and affirmative claims for tax years 1986 through 2002 and related matters with state tax authorities.
GRC	General Rate Case
IRS	Internal Revenue Service
ISO	Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations in this report
Mohave	two coal fueled electric generating facilities that no longer operate located in Clark County, Nevada in which SCE holds a 56% ownership interest
Moody's	Moody's Investors Service
MRTU	Market Redesign Technical Upgrade
MW	megawatts
MWh	megawatt-hours
NAAQS	national ambient air quality standards
NERC	North American Electric Reliability Corporation
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NO_x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
Palo Verde	large pressurized water nuclear electric generating facility located near Phoenix, Arizona in which SCE holds a 15.8% ownership interest
PBOP(s)	postretirement benefits other than pension(s)
PBR	Performance-based ratemaking

PG&E	Pacific Gas & Electric Company
PSD	Prevention of Significant Deterioration
QF(s)	qualifying facility(ies)
ROE	return on equity
S&P	Standard & Poor's Ratings Services
San Onofre	large pressurized water nuclear electric generating facility located in south San Clemente, California in which SCE holds a 78.21% ownership interest
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
SIP(s)	state implementation plan(s)
SO_2	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
US EPA	U.S. Environmental Protection Agency
VIE(s)	variable interest entity(ies)

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 from those currently expected, or that otherwise could impact SCE, include, but are not limited to:

- ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- risks associated with operating nuclear and other power generating facilities, including operating risks; nuclear fuel storage issues; failure, availability, efficiency, output, cost of repairs and retrofits in each case of equipment; and availability and cost of spare parts;
- 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;
- changes in interest rates and rates of inflation, including those rates which may be adjusted by public utility regulators;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and price mitigation strategies adopted by Independent System Operators and Regional Transmission Organizations;
- availability and creditworthiness of counterparties and the resulting effects on liquidity in the power and fuel markets and/or the ability of counterparties to pay amounts owed in excess of collateral provided in support of their obligations;
- cost and availability of labor, equipment and materials;
- ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities and wildfire-related liability, and to recover the costs of such insurance;
- ability to recover uninsured losses in connection with wildfire-related liability;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;

- potential for penalties or disallowances caused by non-compliance with applicable laws and regulations;
- cost and availability of coal, natural gas, fuel oil, and nuclear fuel, and related transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;
- cost and availability of emission credits or allowances for emission credits;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- ability to provide sufficient collateral in support of hedging activities and power and fuel purchased;
- weather conditions and natural disasters;
- risks inherent in the development of generation projects and transmission and distribution infrastructure replacement and expansion projects, including those related to project site identification, construction, permitting, and governmental approvals; and
- risks that competing transmission systems will be built by merchant transmission providers in SCE's territory.

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

PART I

ITEM 1. BUSINESS

SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to an approximately 50,000-square-mile area of southern California. The SCE service territory contains a population of over 13 million people. In 2010, SCE's total operating revenue was derived as follows: 43.5% commercial customers, 39.5% residential customers, 6.0% industrial customers, 1.3% resale sales, 5.8% public authorities, and 3.9% agricultural and other customers. SCE had 18,230 full-time employees at December 31, 2010. SCE's operating revenue was approximately $10 billion in 2010.

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

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

Regulation

CPUC

SCE's retail operations are subject to regulation by the CPUC. The CPUC has the authority to regulate, among other things, retail rates, energy purchases on behalf of retail customers, rate of return, rates of depreciation, issuance of securities, disposition of utility assets and facilities, oversight of nuclear decommissioning funding and costs, and aspects of the transmission system planning, site identification and construction. The governing body of the CPUC consists of five Commissioners who are appointed by the Governor of California, confirmed by the California Senate and serve for six-year staggered terms.

FERC

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

NERC

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

Transmission and Substation Facilities Regulation

The construction, planning and project site identification of SCE's transmission lines and substation facilities require the approval of many governmental agencies and compliance with various laws. These agencies include utility regulatory commissions such as the CPUC and other state regulatory agencies depending on the project location; the CAISO, and other environmental, land management and resource agencies such as the Bureau of Land Management, the U.S. Forest Service, and the California Department of Fish and Game; and regional water quality control boards. In addition, to the extent that SCE transmission line projects pass through lands owned or controlled by Native American tribes, consent and approval from the affected tribes and the Bureau of Indian Affairs are also necessary for the project to proceed.

CEC

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

Nuclear Power Plant Regulation

SCE is subject to the jurisdiction of the NRC with respect to its San Onofre and Palo Verde Nuclear Generating Stations. NRC requirements govern the granting, amendment, and extension of licenses for the construction and operation of nuclear power plants and subject those power plants to continuing oversight, inspection, and performance assessment.

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

Overview of Ratemaking Mechanisms

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

Base Rates

Base rates authorized by the CPUC and the FERC are intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its net investment in generation, transmission and distribution facilities (or "rate base"). These base rates provide for recovery of operations and maintenance costs, capital-related carrying costs (depreciation, taxes and interest) and a return or profit, on a forecast basis.

CPUC Base Rates

Base rates for SCE's generation and distribution functions provide a rate of return and are authorized by the CPUC through triennial GRC proceedings. The CPUC sets an annual revenue requirement for the base year which is made up of the carrying cost on capital investment (depreciation, return and taxes), plus the authorized level of operations and maintenance expense. The return is established by multiplying an authorized rate of return, determined in separate cost of capital proceedings (as discussed below), by SCE's investment in the generation and distribution rate base. In the GRC proceedings, the CPUC also generally approves the level of capital spending on a forecast basis. Adjustments to the revenue requirement for the remaining two years of a typical three-year GRC cycle are requested, based on criteria established in the GRC proceeding, which generally, among other items, include annual allowances for escalation in operation and maintenance costs, forecasted changes in capital-related investments and the timing and number of expected nuclear refueling outages. SCE's GRC decision for the 2009-2011 period was issued in March

2009 and was effective as of January 1, 2009. In the 2009 GRC, the CPUC determined the 2010 and 2011 authorized revenues by escalating the entire revenue requirement. 2009's authorized revenue requirement of $4.83 billion was escalated by 4.25% to create the 2010 authorized amount, which was in turn escalated by 4.35% to create the 2011 authorized amount. SCE filed its 2012 GRC application with the CPUC on November 23, 2010, to be effective on January 1, 2012. The CPUC has authorized a revenue decoupling mechanism, which allows the difference between the revenue authorized and the actual volume of electricity sales to be collected from or refunded to ratepayers. Accordingly, SCE is neither benefited nor burdened by the volumetric risk related to retail electricity sales.

The CPUC regulates SCE's capital structure and authorized rate of return. SCE's current authorized capital structure is 48% common equity, 43% long-term debt and 9% preferred equity. SCE's current authorized cost of capital consists of: cost of long-term debt of 6.22%, authorized cost of preferred equity of 6.01% and authorized return on common equity of 11.5%. In 2008, the CPUC approved a multi-year cost of capital mechanism, which allows for annual adjustments if certain thresholds are reached. In 2009, the CPUC granted SCE's request to extend SCE's existing capital structure and authorized rate of return of 11.5% through December 2012, absent any future potential annual adjustments. The revised mechanism will be subject to CPUC review in 2012 for the cost of capital established for 2013 and beyond. SCE's earnings may be impacted when actual financing costs are above or below its authorized costs for long-term debt and preferred equity financings.

FERC Base Rates

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

Cost-Recovery Rates

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

The CPUC also authorizes the use of a balancing account to eliminate the effect on earnings from differences in revenue resulting from actual and forecasted electricity sales. Under this mechanism, the difference in revenue between actual and forecast electricity sales is recovered from or refunded to ratepayers and therefore does not impact SCE's earnings.

SCE's balancing account for fuel and power procurement-related costs is established under the Energy Resource Recovery Account (''ERRA'') Mechanism. SCE files annual forecasts of the costs that it expects to incur during the following year and sets rates using forecasts. The CPUC has established a ''trigger'' mechanism for the ERRA balancing account that allows for a rate adjustment if the balancing account over-collection or under-collection exceeds 5% of SCE's prior year's generation revenue. For 2011, the trigger amount is approximately $252 million.

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

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

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

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

CDWR-Related Rates

As a result of the California energy crisis, in 2001 the California Department of Water Resources ("CDWR") entered into contracts to purchase power for sale at cost directly to SCE's retail customers and issued bonds to finance those power purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of the investor-owned utilities (SCE, PG&E and SDG&E). SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. The CDWR-related charges and a portion of direct access exit fees that are remitted directly to the CDWR are not recognized as electric utility revenue; but do affect customer rates. The remaining CDWR power contracts that were allocated to SCE terminate by the end of 2011. The bond-related charges and direct access exit fees continue until 2022.

Competition

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

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

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

Purchased Power and Fuel Supply

SCE obtains the power needed to serve its customers from its generating facilities and from sales by qualifying facilities, independent power producers, renewable power producers, the CAISO, and other utilities. In addition, power is provided to SCE's customers through purchases by the CDWR under contracts with third parties.

Natural Gas Supply

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

Nuclear Fuel Supply

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

Uranium concentrates	2020
Conversion	2020
Enrichment	2020
Fabrication	2015

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

Uranium concentrates	2017
Conversion	2018
Enrichment	2020
Fabrication	2016

Coal Supply

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

CAISO Wholesale Energy Market

In California and other states, wholesale energy markets exist through which competing electricity generators offer their electricity output to electricity retailers. Each state's wholesale electricity market is generally operated by its state ISO or a regional RTO. California's wholesale electricity market is operated by the CAISO. The CAISO schedules power in hourly increments with hourly prices through a real-time and day-ahead market that combines energy, ancillary services, unit commitment and congestion management. SCE participates in the day-ahead and real-time markets for the sale of its generation and purchases of its load requirements.

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

Properties

SCE supplies electricity to its customers through extensive transmission and distribution networks. Its transmission facilities, which are located primarily in California but also in Nevada and Arizona, deliver power from generating sources to the distribution network and consist of lines ranging from 33 kV to 500 kV and substations. SCE's distribution system, which takes power from substations to customers, includes over 60,000 circuit miles of overhead lines, 43,500 circuit miles of underground lines and over 700 distribution substations, all of which are located in California.

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

Generating Facility	Location (in CA, unless otherwise noted)	Fuel Type	SCE's Ownership Interest (%)	Net Physical Capacity (in MW)	SCE's Capacity pro rata share (in MW)
San Onofre Nuclear Generating Station	South of San Clemente	Nuclear	78.21%	2,150	1,760
Hydroelectric Plants (36)	Various	Hydroelectric	100%	1,176	1,176
Pebbly Beach Generating Station	Catalina Island	Diesel	100%	9	9
Mountainview	Redlands	Natural Gas	100%	1,050	1,050
Peaker Plants (4)	Various	Gas fueled Combustion Turbine	100%	196	196
Palo Verde Nuclear Generating Station	Phoenix, AZ	Nuclear	15.8%	3,739	591
Four Corners Units 4 and 5	Farmington, NM	Coal-fired	48%[1]	1,500	720
Total				9,820	5,502

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

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

Twenty-eight of SCE's 36 hydroelectric plants and related reservoirs are located in whole or in part on U.S.-owned lands pursuant to 30- to 50-year FERC licenses that expire at various times between 2011 and 2040. Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire projects upon payment of specified compensation. When existing licenses expire, the FERC has the authority to issue new licenses to third parties that have filed competing license applications, but only if their license application is superior to SCE's and then only upon payment of specified compensation to SCE. New licenses issued to SCE are expected to contain more restrictions and obligations than the expired licenses because laws enacted since the existing licenses were issued require the FERC to give environmental objectives greater consideration in the licensing process.

Substantially all of SCE's properties are subject to the lien of a trust indenture securing first and refunding mortgage bonds. See "Item 8. SCE Notes to Consolidated Financial Statements Note 5. Debt and Credit Agreements."

SCE's rights in Four Corners, which is located on land of the Navajo Nation under an easement from the United States and a lease from the Navajo Nation, may be subject to defects. These defects include possible conflicting grants or encumbrances not ascertainable because of the absence of, or inadequacies in, the applicable recording law and record systems of the Bureau of Indian Affairs and the Navajo Nation, the possible inability of SCE to resort to legal process to enforce its rights against the Navajo Nation without Congressional consent, the possible impairment or termination under certain circumstances of the easement and lease by the Navajo Nation, Congress, or the Secretary of the Interior, and the possible invalidity of the trust indenture lien against SCE's interest in the easement, lease, and improvements on Four Corners. For more information on SCE's sale of its interest in Four Corners, see "Item 8. SCE Notes to Consolidated Financial Statements Note 2. Property, Plant and Equipment."

Insurance

SCE participates in the property and casualty insurance program of its parent, Edison International. This program includes excess liability insurance covering liabilities to third parties for bodily injury or property damage resulting from operations. For further information on wildfire insurance issues, see "Item 8. SCE Notes to Consolidated Financial Statements—Note 10. Regulatory and Environmental Developments." SCE also has separate insurance programs for nuclear property and liability, workers compensations and solar rooftop construction liability.

Seasonality

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

Environmental Matters

Legislative and regulatory activities by federal, state, and local authorities in the United States relating to energy and the environment impose numerous restrictions on the operation of SCE's existing facilities and affect the timing, cost, location, design, construction and operation of new facilities, as well as the cost of mitigating the environmental impacts of past operations. The environmental regulations and other developments discussed below have the largest impact on fossil-fuel fired power plants, and therefore the discussion in this section focuses mainly on regulations applicable to the states of California and New Mexico, where such facilities are located.

SCE continues to monitor legislative and regulatory developments and to evaluate possible strategies for compliance with environmental regulations. Additional information about environmental matters affecting SCE, including projected environmental capital expenditures, is included 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 9. Commitments and Contingencies—Environmental Remediation" and "—Note 10. Regulatory and Environmental Developments."

Greenhouse Gas Regulation

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

Federal Legislative/Regulatory Developments

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

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

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

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

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

Regional Initiatives and State Legislation

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

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

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

SB 1368 also affects the ability of utilities to make long-term capital investments in generators that do not meet the emission performance standards. SB 1368 may prohibit SCE from making emission control expenditures at Four Corners. See "Item 8. SCE Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment" for information on the sale of SCE's interest in Four Corners.

California law also requires SCE to increase its electricity generated from renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are provided from such resources (the "RPS Program") by no later than December 31, 2010 or such later date as flexible compliance requirements permit. Through December 31, 2010, SCE estimates its delivery of eligible renewable resources to customers to be 19% of its total energy portfolio. In accordance with the procurement rules and regulations, SCE expects to demonstrate full compliance with the RPS Program in its March 2011 filing. In addition, in September 2010, the CARB adopted a Renewable Electricity Standard, which requires SCE to demonstrate renewable energy production equal to 33% of its sales to retail customers for 2020 and each year thereafter. Subsequently, in February 2011, a California Senate bill was introduced that would impose a similar requirement that California utilities purchase 33% of their electricity requirements from renewable resources. It is unclear whether the legislation will preempt the CARB's standard, if it is enacted.

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

Litigation Developments

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

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

SCE cannot predict whether the legal principles emerging from the Supreme Court or any of the cases in the appellate courts will result in the filing of new actions with similar claims or whether Congress, in considering climate legislation, will address directly the availability of courts to resolve claims associated with climate change.

Air Quality

The CAA, which regulates air pollutants from mobile and stationary sources, has a significant impact on the operation of fossil fuel plants, especially coal-fired plants. The CAA requires the US EPA to establish concentration levels in the ambient air for six criteria pollutants to protect public health and welfare. These concentration levels are known as National Ambient Air Quality Standards, or NAAQS. The six criteria pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and SO_2.

Federal environmental regulations of these criteria pollutants require states to adopt state implementation plans, known as SIPs, for certain pollutants, which detail how the state will attain the standards that are mandated by the relevant law or regulation. The SIPs must be equal to or more stringent than the federal requirements and must be submitted to the US EPA for approval. Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas), and must develop a SIP both to bring non-attainment areas into compliance with the NAAQS and to maintain good air quality in attainment areas. If the attainment status of areas changes, states may be required to develop new SIPs that address the changes. Much of Southern California is in a non-attainment area for several criteria pollutants.

Sulfur Dioxide

Proposed NAAQS for Sulfur Dioxide

In June 2010, the US EPA finalized the primary NAAQS for SO_2 by establishing a new one-hour standard at a level of 75 parts per billion. Revisions to SIPs to achieve compliance with the new standard are due to be submitted to the US EPA by February 2014, with a compliance deadline of August 2017.

Ozone and Particulates

National Ambient Air Quality Standards

In January 2010, the US EPA proposed a revision to the primary and secondary NAAQS for 8-hour ozone that it had finalized in 2008. The 8-hour ozone standard established in 2008 was 0.075 parts per million. In January 2010, the US EPA proposed establishing a primary 8-hour ozone NAAQS between 0.060 and 0.070 parts per million and a distinct secondary standard to protect sensitive vegetation and ecosystems. The US EPA is expected to finalize the revision to the ozone NAAQS by July 2011. It is expected that once the US EPA finalizes the revised ozone NAAQS, it will propose a second Transport Rule that may further affect electric power generating units. The US EPA is also expected to propose revised fine particulate matter NAAQS in 2011, which could result in further emission reduction requirements in future years.

Mercury/Hazardous Air Pollutants

Clean Air Mercury Rule/Hazardous Air Pollutant Regulations

The CAMR was established by the US EPA as an attempt to reduce mercury emissions from existing coal-fired power plants using a cap-and-trade program. In February 2007, the U.S. Court of Appeals for the D.C. Circuit vacated both the CAMR and the related US EPA decision to remove oil- and coal-fired power plants from the list of sources to be regulated under the provisions of the CAA governing the emissions of HAPs.

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

Regional Haze

The regional haze rules under the CAA are designed to prevent impairment of visibility in certain federally designated areas. The goal of the rules is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions by 2064. Sources such as power plants that are reasonably anticipated to contribute to visibility impairment in Class I areas may be required to install best available retrofit technology ("BART") or implement other control strategies to meet regional haze control requirements. The US EPA issued a final rulemaking on regional haze in 2005 requiring emission controls that constitute BART for industrial facilities that emit air pollutants which reduce visibility by causing or contributing to regional haze. These amendments required states to develop SIPs to comply with BART by December 2007, to identify the facilities that will have to reduce SO_2, NO_x and particulate matter emissions, and then to set BART emissions limits for those facilities. Failure to do so would result in the imposition of a federal implementation plan ("FIP"). Because the Four Corners plant is located on the Navajo Reservation there is no applicable SIP and the plant will be subject only to a FIP.

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

New Source Review Requirements

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

In April 2009, APS, as operating agent of Four Corners, received a US EPA request pursuant to Section 114 of the CAA for information about Four Corners, including information about Four Corners' capital projects from 1990 to the present. SCE understands that in other cases the US EPA has utilized responses to similar Section 114 letters to examine whether power plants have triggered NSR requirements under the CAA. In May 2010, four environmental organizations (Dine CARE, National Parks Conservation Association, Sierra Club, and To Nizhoni Ani) served SCE and the other Four Corners owners with a notice of intent to sue under the CAA alleging violations of NSR requirements. The US EPA has not initiated any NSR enforcement-related proceedings with respect to Four Corners. SCE has entered into an agreement to sell Four Corners. See "Item 8. SCE Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment," for more information on the sale of SCE's interest in Four Corners.

Water Quality

Clean Water Act

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

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

California has a US EPA-approved program to issue individual or group (general) permits for the regulation of Clean Water Act discharges. California also regulates certain discharges not regulated by the

US EPA. In May 2010 the California State Water Resources Control Board issued a final policy, which establishes closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like SCE's San Onofre and many of the existing fossil-fueled power plants along the California coast. The final policy, which took effect on October 1, 2010, requires an independent engineering study to be completed prior to the fourth quarter of 2013 regarding the feasibility of compliance by California's two coastal nuclear power plants, which may result in significant capital expenditures at San Onofre and may affect its operations. The policy could adversely affect California's nineteen once-through cooled power plants, which provide over 21,000 MW of combined, in-state generation capacity, including over 9,100 MW of capacity interconnected within SCE's service territory. The policy may also significantly impact SCE's ability to procure generating capacity from fossil-fuel plants that use ocean water in once-through cooling systems, system reliability and the cost of electricity if other coastal power plants in California are forced to shut down or limit operations.

Coal Combustion Wastes

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

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

ITEM 1A. RISK FACTORS

Regulatory Risks

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

SCE's ongoing financial results depend on its ability to recover from its customers in a timely manner its costs, including the costs of electricity purchased for its customers, through the rates it charges its customers as approved by the CPUC, and its ability to pass through to its customers in rates its FERC-authorized revenue requirements. SCE's financial results also depend on its ability to earn through the rates it is allowed to charge an adequate return on capital, including long-term debt and equity. SCE's capital investment plan, California's commitment to renewable power, increasing environmental regulations, sensitivity to increasing natural gas costs and moderating demand, collectively place continuing upward pressure on customer rates. If SCE is unable to obtain a sufficient rate increase or to recover material amounts of its costs in rates in a timely manner or recover an adequate return on capital, its financial condition and results of operations could be materially adversely affected. For further information on SCE's rate requests, see "Management Overview—SCE Rate Cases" in the MD&A.

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

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

SCE may not be able to hedge its risk for commodities on economic terms or fully recover the costs of hedges through the rates it is allowed to charge its customers, which could adversely affect SCE's liquidity and results of operations, see "Market Risk Exposures" in the MD&A.

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 NRC regulates SCE's nuclear power plants. The construction, planning, and project site identification of SCE's power plants and transmission lines in California are also subject to the jurisdiction of the California Energy Commission (for plants 50 MW or greater) and the CPUC. The construction, planning and project site identification of transmission lines that are outside of California are subject to the regulation of the relevant state agency.

SCE must periodically apply for licenses and permits from these various regulatory authorities and abide by their respective orders. Should SCE be unsuccessful in obtaining necessary licenses or permits or should these regulatory authorities initiate any investigations or enforcement actions or impose penalties or disallowances on SCE, SCE's business could be adversely affected.

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

Environmental Risks

SCE is subject to extensive environmental regulations that may involve significant and increasing costs and adversely affect SCE.

SCE is subject to extensive and frequently changing environmental regulations and permitting requirements that involve significant and increasing costs and substantial uncertainty. 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 adoption of laws and regulations to implement greenhouse gas controls could adversely affect operations, particularly of the coal-fired plants. SCE may also be exposed to risks arising from past, current or future contamination at its former or existing facilities or with respect to off site waste disposal sites that have been used in its operations. Other environmental laws, particularly with respect to air emissions, disposal of ash, wastewater discharge and cooling water systems, are also generally becoming more stringent. The continued operation of SCE facilities, particularly the coal-fired facilities, may require substantial capital expenditures for environmental controls or cessation of operations. Current and future state laws and regulations in California also could increase the required amount of energy that must be procured from renewable resources. See "Item 1. Business—Environmental Matters" for further discussion of environmental regulations under which SCE operates.

Operating Risks

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

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

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

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

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

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

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection which is currently approximately $12.6 billion. SCE and other owners of the San Onofre and Palo Verde Nuclear Generating Stations have purchased the maximum private primary insurance available of $375 million per site. If nuclear incident liability claims were to exceed $375 million, the remaining amount would be made up from contributions of approximately $12.2 billion made by all of the nuclear facility owners in the U.S., up to an aggregate total of $12.6 billion. There is no assurance that the CPUC would allow SCE to recover the required contribution made in the case of a nuclear incident claim(s) that exceeded $375 million. If this public liability limit of $12.6 billion is insufficient, federal law contemplates that additional funds may be appropriated by Congress. There can be no assurance of SCE's ability to recover uninsured costs in the event the additional federal appropriations are insufficient.

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

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

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

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

Financing Risks

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

SCE regularly accesses capital markets to finance its activities and is expected to do so by its regulators as part of its obligation to serve as a regulated utility. SCE's needs for capital for its ongoing infrastructure investment program are substantial. SCE's ability to arrange financing, as well as its ability to refinance debt and make scheduled payments of principal and interest, are dependent on numerous factors, including SCE's levels of indebtedness, maintenance of acceptable credit ratings, its financial performance, liquidity and cash flow, and other market conditions. SCE's failure to obtain additional capital from time to time would have a material adverse effect on SCE's liquidity and operations. See "Liquidity and Capital Resources—Capital Investment Plan" and "Liquidity and Capital Resources—Historical Consolidated Cash Flows" in the MD&A.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The principal properties of SCE are described above under the heading "Business—Properties."

ITEM 3. LEGAL PROCEEDINGS

California Coastal Commission Potential Environmental Proceeding

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

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

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

EXECUTIVE OFFICERS OF THE REGISTRANT

Executive Officer	Age at December 31, 2010	Company Position
Ronald L. Litzinger	51	President
Stephen E. Pickett	60	Executive Vice President, External Relations
Russell C. Swartz	59	Senior Vice President and General Counsel
Peter T. Dietrich	46	Senior Vice President and Chief Nuclear Officer
Stuart R. Hemphill	47	Senior Vice President, Power Supply
Linda G. Sullivan	47	Senior Vice President and Chief Financial Officer
Chris C. Dominski	44	Vice President and Controller
Lynda L. Ziegler	58	Executive Vice President, Power Delivery Services

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, Edison International, and/or one of SCE's subsidiaries or other affiliates for more than five years, except for Mr. Dietrich, 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
Ronald L. Litzinger	President, SCE	January 2011 to present
	Chairman of the Board, President and Chief Executive Officer, Edison Mission Group Inc.	April 2008 to December 2010
	Senior Vice President, Transmission and Distribution, SCE	May 2005 to March 2008
Stephen E. Pickett	Executive Vice President, External Relations, SCE	February 2011 to present
	Executive Vice President, External Relations and General Counsel, SCE	January 2011 to February 2011
	Senior Vice President and General Counsel, SCE	January 2002 to December 2010
Russell C. Swartz	Senior Vice President and General Counsel, SCE	February 2011 to present
	Vice President and Associate General Counsel, SCE	February 2010 to February 2011
	Associate General Counsel, SCE	March 2007 to February 2010
	Assistant General Counsel, SCE	February 2002 to February 2007
Peter T. Dietrich	Senior Vice President and Chief Nuclear Officer, SCE	December 2010 to present
	Senior Vice President, SCE	November 2010 to present
	Site Vice President, Entergy Nuclear Operations, Inc. James A. Fitzpatrick Nuclear Plant[1]	April 2006 to November 2010
	General Manager Plant Operations, Entergy's Pilgrim Nuclear Station	January 2006 to April 2006
Stuart R. Hemphill	Senior Vice President, Power Supply	January 2011 to present
	Senior Vice President, Power Procurement, SCE	July 2009 to December 2010
	Vice President, Renewable and Alternative Power	March 2008 to June 2009
	Director of Renewable and Alternative Power	April 2006 to March 2008
Linda G. Sullivan	Senior Vice President and Chief Financial Officer, SCE	March 2010 to present
	Senior Vice President, Chief Financial Officer and Acting Controller, SCE	July 2009 to March 2010
	Vice President and Controller, Edison International	June 2005 to August 2009
	Vice President and Controller, SCE	June 2005 to June 2009
Chris C. Dominski	Vice President, and Controller, SCE	March 2010 to present
	Assistant Controller, Edison International	March 2007 to April 2010
	Assistant Controller, SCE	March 2007 to March 2010
	Manager, Financial Planning and Analysis, SCE	July 2006 to March 2007
Lynda L. Ziegler	Executive Vice President, Power Delivery Services, SCE	January 2011 to present
	Senior Vice President, Customer Service, SCE	March 2006 to December 2010
	Vice President, Customer Programs and Services Division, SCE	May 2005 to February 2006

[1] Entergy Nuclear Operations, Inc. is a subsidiary of Entergy Corporation, which is an integrated energy company.

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 the Consolidated Financial Statements—Note 17. Quarterly Financial Data." As a result of the formation of a holding company described in Item 1 above, 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: 2006 – 2010

(Dollars in millions)	2010	2009	2008	2007	2006
Income statement data:					
Operating revenue	$ 9,983	$ 9,965	$ 11,248	$ 10,233	$ 9,859
Operating expenses	8,119	8,047	9,595	8,492	8,003
Net income	1,092	1,371	904	1,063	1,102
Net income available for common stock	1,040	1,226	683	707	776
Balance sheet data:					
Total assets	$ 35,906	$ 32,474	$ 32,568	$ 27,477	$ 26,110
Long-term debt including current portion	7,627	6,740	6,362	5,081	5,567
Common shareholder's equity	8,287	7,446	6,513	6,228	5,447
Preferred and preference stock	920	920	920	929	929
Capital structure:					
Common shareholder's equity	49.2%	49.3%	47.2%	50.9%	45.6%
Preferred and preference stock	5.5%	6.1%	6.7%	7.6%	7.8%
Long-term debt	45.3%	44.6%	46.1%	41.5%	46.6%

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

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

Highlights of Operating Results

(in millions)	2010	2009	Change	2008
Net Income available for common stock	$ 1,040	$ 1,226	$ (186)	$ 683
Non-Core Items				
Global Settlement	95	306	(211)	—
Tax impact of health care legislation	(39)	—	(39)	—
Regulatory items	—	46	(46)	(49)
Total non-core items	56	352	(296)	(49)
Core Earnings	$ 984	$ 874	$ 110	$ 732

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 SCE's earnings results to facilitate comparisons of the performance from period to period. Core earnings are a non-GAAP financial measure and may not be comparable to those of other companies. Core earnings are defined as earnings attributable to SCE less income or loss from significant discrete items that management does not consider representative of ongoing earnings, such as: settlement of certain tax, regulatory or legal matters or proceedings.

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

Consolidated non-core items for SCE included:

- An after-tax earnings benefit of $95 million recorded in 2010 relating to the California impact of the federal Global Settlement resulting from acceptance by the California Franchise Tax Board of tax positions finalized with the IRS in 2009 and a revision to interest recorded on the federal Global Settlement. In 2009, SCE recorded an after-tax earnings benefit of $306 million related to the Global Settlement with the IRS. For further discussion of the Global Settlement see "Item 8. SCE Notes to Consolidated Financial Statements—Note 7. Income Taxes."
- An after-tax earnings charge of $39 million recorded in 2010 to reverse previously recognized federal tax benefits eliminated by the recently enacted federal health care legislation. The new health care law eliminates the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies.
- An after-tax earnings benefit of $46 million recorded in 2009 resulting from the transfer of the Mountainview power plant to utility rate base pursuant to CPUC and FERC approvals.

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

Capital Program

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

- Maintaining reliability and expanding the capability of SCE's transmission and distribution system.
- Upgrading and constructing new transmission lines for system reliability and increased access to renewable energy, including the Tehachapi, Devers-Colorado River, Eldorado-Ivanpah, Red Bluff and Alberhill projects.
- Generation investments for nuclear and hydro-electric plant betterment projects and general facilities and technology needs.
- Installing "smart" meters in households and small businesses, referred to as EdisonSmartConnect™. Through 2010, SCE installed 2 million smart meters and plans to complete installation of the remaining 3.3 million meters during 2011 and 2012.

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

Rate Cases

2012 CPUC General Rate Case

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

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

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

FERC 2010 Rate Case

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

NRC Oversight of San Onofre

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

Bonus Depreciation

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

- result in a consolidated net operating loss for federal income tax purposes for 2010 and 2011;
- provide additional cash flow benefits during 2011 of approximately $550 million; and
- eliminate income tax benefits from the domestic production activities deduction (also known as Section 199 deductions) of $16 million in 2011.

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

Environmental Developments

For a discussion of environmental regulation developments regarding Greenhouse Gas Regulation, and California Once-Through Cooling issues, see "Item 8. SCE Notes to Consolidated Financial Statements—Note 10. Regulatory and Environmental Developments."

RESULTS OF OPERATIONS

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

- Utility earning activities – representing CPUC and FERC-authorized base rates, including an authorized reasonable return, and CPUC-authorized incentive mechanisms; and
- Utility cost-recovery activities – representing CPUC-authorized balancing accounts which allow for recovery of costs incurred or provide for mechanisms to track and recover or refund differences in forecasted and actual amounts.

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

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

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.

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

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

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

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

Utility Earning Activities

2010 vs. 2009

Utility earning activities were primarily affected by the following:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2009 vs. 2008

Utility earning activities were primarily affected by:

- Higher operating revenue of $447 million primarily due to the following:

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

  - $114 million increase resulting from the implementation of SCE's 2009 FERC approved rate case settlement effective March 1, 2009.

    - $25 million decrease due to the presentation of revenue requirements for medical, dental, and vision expenses and SCE's share of Palo Verde operation and maintenance expenses, which beginning in 2009 are reflected in utility cost-recovery activities consistent with the balancing account ratemaking treatment authorized in SCE's 2009 GRC.

- Higher operation and maintenance expenses of $32 million primarily due to:
    - $105 million of higher transmission and distribution expenses primarily due to higher costs to support system reliability and infrastructure projects, increases in preventive maintenance work, as well as engineering costs.
    - $50 million of higher expenses related to regulatory and performance issues, including the NRC requiring SCE to take action to provide greater assurance of compliance by San Onofre personnel with applicable NRC requirements and procedures (See "Item 1. Business—Regulation—Nuclear Power Plant Regulation" for further discussion).
    - $50 million of higher expenses associated with new information technology system requirements and facility maintenance to support company growth programs.
    - $175 million decrease due to presentation of medical, dental and vision expenses and SCE's share of Palo Verde operations and maintenance expenses, which beginning in 2009 are reflected in cost-recovery activities consistent with the balancing account ratemaking treatment authorized in SCE's 2009 GRC.
- Higher depreciation expense of $69 million primarily resulting from increased capital expenditures including capitalized software costs.
- Lower net interest expense and other of $116 million primarily due to:
    - Lower other expenses of $71 million primarily due to a final charge of $60 million ($49 million after-tax) recorded in 2008 resulting from the CPUC decision on SCE's PBR mechanism, as well as a $14 million decrease in civic, political and related activity expenditures primarily related to spending on Proposition 7 in 2008. These decreases were partially offset by an $8 million increase in donations.
    - Higher other income of $61 million due to an increase in AFUDC – equity earnings primarily resulting from a $50 million one-time gain resulting from the transfer of the Mountainview power plant to utility rate base authorized in SCE's 2009 GRC and a $12 million increase resulting from a higher level of construction work in progress associated with SCE's capital expenditure program.
    - Higher interest expense of $8 million primarily due to higher outstanding balances on long-term debt partially offset by lower interest expense on short-term borrowings. Due to an increase in cash flow from operations, including the positive cash impact from the Global Settlement and other tax timing differences, SCE was able to defer some of its expected financings in 2009 to support its growth programs.

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

Utility Cost-Recovery Activities

2010 vs. 2009

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

- Lower purchased power expense of $191 million related to: lower realized losses on economic hedging activities ($156 million in 2010 compared to $344 million in 2009) reflecting the impact of higher natural gas prices and changes in SCE's hedge portfolio mix; lower bilateral energy purchase expense of

$50 million primarily due to decreased kWh purchases associated with overall lower kWh demand; and lower net ISO-related and other energy costs of $50 million primarily due to milder weather experienced during 2010 compared to 2009. These decreases were partially offset by the purchase of replacement power costs related to the San Onofre Unit 2 extended outage and higher QF and renewable purchased power expense of $85 million primarily due to higher natural gas prices.

- Higher fuel expense of $10 million related to a $25 million increase at the Mountainview power plant resulting from higher natural gas prices and a $10 million decrease at Four Corners resulting from a planned outage in 2010.
- Higher operation and maintenance expense of $71 million primarily due to an increase in spending for various public purpose programs.

2009 vs. 2008

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

- Lower purchased power expense of $1.4 billion primarily due to: lower bilateral energy and QF purchases of $1.6 billion primarily due to lower natural gas prices and decreased kWh purchases; and lower firm transmission rights costs of $65 million due to implementation of CAISO's MRTU market; and a change in net realized losses due to settled natural gas prices being significantly lower than average fixed prices. Realized losses on economic hedging activities were $344 million in 2009 and $60 million in 2008.

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

- Higher operation and maintenance expense of $105 million primarily related to the presentation of $185 million of medical, dental, and vision expenses and its share of Palo Verde operation and maintenance expenses which beginning in 2009 are reflected in cost-recovery activities consisting with the balancing account ratemaking treatment authorized in SCE's 2009 GRC. In addition, SCE recorded higher pension and PBOP expenses of $60 million due to the volatile market conditions experienced in 2008. These increases were partially offset by $50 million of lower energy efficiency costs and $85 million of lower transmission access and reliability service charges.

Supplemental Operating Revenue Information

SCE's retail billed and unbilled revenue (excluding wholesale sales and balancing account over/undercollections) was $10 billion, $9.5 billion and $9.3 billion for 2010, 2009 and 2008. The 2010 and 2009 increases reflect a rate increase of $777 million and $564 million, respectively, and a sales volume decrease of $255 million and $380 million, respectively. The 2010 rate increase was due to higher system average rates for 2010 compared to the same periods in 2009 mainly due to the implementation of the CPUC 2009 GRC decision and approved FERC transmission rate changes. The 2010 sales volume decrease was primarily due to milder weather experienced during 2010 compared to the same period in 2009. Economic conditions continued to contribute to the sales volume decrease. The 2009 rate increase reflects a rate change effective April 4, 2009 due to the implementation of both revenue allocation and rate design changes authorized in Phase 2 of the 2009 GRC and the FERC transmission rate changes authorized in the 2009 FERC Rate Case. The 2009 sales volume decrease was due to the economic downturn as well as the milder weather experienced in 2009 compared to the same period in 2008. As a result of the CPUC-authorized decoupling mechanism, SCE does not bear the volumetric risk related to retail electricity sales (see "Item 1. Business—Overview of Ratemaking Mechanisms").

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

Income Taxes

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

Available Liquidity

As of December 31, 2010, SCE had approximately $257 million of cash and equivalents. SCE had two credit facilities: a $2.4 billion five-year credit facility that matures in February 2013, with four one-year options to extend by mutual consent, and a $500 million three-year credit facility that matures in March 2013.

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

Debt Covenant

SCE has a debt covenant in its credit facilities that limits its debt to total capitalization ratio to less than or equal to 0.65 to 1. At December 31, 2010, SCE's debt to total capitalization ratio was 0.46 to 1.

Capital Investment Plan

SCE's capital expenditures for 2011 – 2014 include a capital forecast in the range of $15.6 billion to $17.5 billion. The 2011 planned capital expenditures for projects under CPUC jurisdiction are recovered through the authorized revenue requirement in SCE's 2009 GRC or through other CPUC-authorized mechanisms. Recovery of the 2012 – 2014 planned capital expenditures for projects under CPUC jurisdiction and not already approved through other CPUC-authorized mechanisms, is subject to the outcome of the 2012 CPUC GRC or other CPUC approvals. The 2011 planned capital expenditures for projects under FERC jurisdiction are recovered through the authorized FERC revenue requirement. Recovery of the 2012 – 2014 planned capital expenditures under FERC jurisdiction will be requested in future FERC transmission filings, as applicable.

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

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

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

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

Distribution Projects

Distribution expenditures include projects and programs to meet customer load growth requirements, reliability and infrastructure replacement needs, information and other technology and related facility requirements. Of the total forecasted distribution expenditures, $2.0 billion are recoverable through rates authorized in SCE's 2009 CPUC GRC decision, and $7.1 billion are subject to review and approval in the 2012 CPUC GRC proceeding.

Transmission Projects

SCE's has planned the following significant transmission projects:

- Tehachapi Transmission Project – an 11-segment project consisting of new and upgraded transmission lines and associated substations primarily built to enhance reliability and enable the delivery of renewable energy generated primarily by wind farms in remote areas of eastern Kern County, California. Tehachapi segments 1, 2 and a portion of segment 3 were completed and placed in service in 2009. The remainder of segment 3 is under construction and expected to be placed in service over the period 2012 – 2013. SCE continues to seek the necessary licensing permits for Tehachapi segments 4 through 11, which are expected to be placed in service between 2011 and 2015, subject to receipt of licensing and regulatory approvals. SCE expects to invest $1.3 billion over the period 2011 – 2014 on this project. The FERC approved a 125 basis point ROE project adder, a 50 basis point incentive for CAISO participation, 100% CWIP in rate base treatment, and the ability to seek recovery of 100% abandoned plant costs (if any) on this project.

- Devers-Colorado River Project – a transmission project involving the installation of a high voltage (500 kV) transmission line from western Riverside County, California to the Colorado River switchyard west of Blythe, California. The project is currently expected to be placed in service in 2013, subject to final licensing and regulatory approvals. Over the period 2011 – 2013, SCE expects to invest $655 million for this project. The FERC approved a 100 basis point ROE project adder, a 50 basis point adder for CAISO participation, 100% CWIP in rate base treatment and the ability to seek recovery of 100% abandoned plant costs (if any) on this project.

- Eldorado-Ivanpah Transmission Project – a proposed 220/115 kV substation near Primm, Nevada and an upgrade of a 35-mile portion of an existing transmission line connecting the new substation to the Eldorado Substation, near Boulder City, Nevada. The project is currently expected to be placed in service in 2013, subject to necessary licensing and regulatory approvals. SCE expects to invest $483 million over the period 2011 – 2013 on this project. The FERC approved a 50 basis point incentive for CAISO participation, 100% CWIP in rate base treatment, and the ability to seek recovery of 100% abandoned plant costs (if any) on this project.

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

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

Generation Projects

Generation expenditures of $2.3 billion include:

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

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

EdisonSmartConnect™

SCE's EdisonSmartConnect™ project involves installing state-of-the-art "smart" meters in approximately 5.3 million households and small businesses through its service territory. In March 2008, SCE was authorized by the CPUC to recover $1.63 billion in customer rates for the deployment phase of EdisonSmartConnect™. In 2009, SCE began full deployment of meters to all residential and small business customers under 200 kW. SCE anticipates completion of the deployment in 2012.

Solar Rooftop Program

In June 2009, the CPUC approved SCE's Solar Photovoltaic Program to develop up to 250 MW of utility-owned Solar Photovoltaic generating facilities generally ranging in size from 1 to 2 MW each, on commercial and industrial rooftops and other space in SCE's service territory. The CPUC has authorized recovery of reasonable costs and allowed for a return on its investment. In February 2011, SCE filed an application with the CPUC to reduce the maximum utility owned solar projects from 250 MW to 125 MW and to allow SCE to purchase power from new solar projects up to 125 MW in a separate solicitation not subject to the same parameters as the original Program. SCE filed this application to permit greater competition and reduce overall solar program customer costs. SCE's capital expenditures for the period 2011 – 2014 reflect this reduction in procurement obligations and related estimated cost savings.

Regulatory Proceedings

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

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

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

Ratemaking Mechanism to Track Bonus Depreciation

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

Dividend Restrictions

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the 48% authorized level on a 13-month weighted average basis. At December 31, 2010, SCE's 13-month weighted-average common equity component of total capitalization was 51% resulting in the capacity to pay $497 million in additional dividends.

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

Income Tax Matters

Repair Deductions

In 2009, Edison International made a voluntary election to change its tax accounting method for certain repair costs incurred on SCE's transmission, distribution and generation assets. The change in tax accounting method resulted in a $192 million cash benefit realized in the fourth quarter of 2009. This initial benefit was based on an estimated cumulative catch-up deduction for certain repair costs that were previously capitalized and depreciated over the tax depreciable life of the property. The deduction reflected on the 2009 income tax return was consistent with this cash benefit. The amount claimed on the 2009 tax return may be revised in the future based on further guidance from the IRS. The income tax benefit from the change in accounting for repair costs represents a timing difference which will reverse over the estimated remaining tax life of the assets. This method change, and incremental deductions taken in 2009 and 2010, did not impact SCE's 2009 or 2010 results of operations. Regulatory treatment for future increases in income taxes related to this matter will be addressed in SCE's 2012 GRC. SCE has not recognized an earnings benefit or regulatory asset, as the regulatory treatment is pending.

Margin and Collateral Deposits

Derivative Instruments and Power Procurement Contracts

Certain derivative instruments and power procurement contracts under SCE's power and natural gas hedging activities contain collateral requirements. SCE has historically provided collateral in the form of cash and/or letters of credit for the benefit of counterparties. Collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments, and other factors. Future collateral requirements may be higher (or lower) than requirements at December 31, 2010, due to the addition of incremental power and energy procurement contracts with collateral requirements, if any, and the impact of changes in wholesale power and natural gas prices on SCE's contractual obligations.

Certain of these power procurement contracts contain a provision that requires SCE to maintain an investment grade credit rating from the major credit rating agencies. If SCE's credit rating were to fall below investment grade, SCE may be required to pay the liability or post additional collateral. The table below illustrates the amount of collateral posted by SCE to its counterparties as well as the potential collateral that would be required as of December 31, 2010.

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

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

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

Potential Regulation of Swaps under the Dodd-Frank Act

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

The Dodd-Frank Act subjects Swaps to new mandatory clearing and trading requirements, if no exemption applies. It may also impose capital requirements on non-exempt market participants. The clearing and trading requirements could result in increased margining requirements which may increase the costs of hedging activity. SCE uses Swap transactions to hedge commodity price risk and is subject to oversight by the CPUC.

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

Workers Compensation Self-Insurance Fund

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

Regulatory Balancing Accounts

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

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

Historical Consolidated Cash Flows

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

Condensed Consolidated Statement of Cash Flows

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

Net Cash Provided by Operating Activities

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

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

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

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

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

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

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

- $875 million cash inflow from the receipt of payments due to Global Settlement related to the settlement of affirmative claims, a portion of which is timing and will be payable in future periods.

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

Net Cash Provided (Used) by Financing Activities

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

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

- Issued $1 billion of first refunding mortgage bonds due in 2040 to fund SCE's capital program.
- Reissued $144 million of tax-exempt pollution control bonds due in 2035 to fund SCE's capital program.
- Repaid $250 million of senior unsecured notes.
- Paid $300 million in dividends to Edison International.

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

- Issued $500 million of first refunding mortgage bonds due in 2039 and $250 million of first and refunding mortgage bonds due in 2014. The bond proceeds were used for general corporate purposes and to finance fuel inventories.
- Repaid a net $1.9 billion of short-term debt.
- Repaid $150 million of first and refunding mortgage bonds.
- Purchased $219 million of two issues of tax-exempt pollution control bonds and converted the issues to a variable rate structure. As discussed above, SCE reissued $144 million of these bonds in 2010. SCE continues to hold the remaining $75 million of these bonds which are outstanding and have not been retired or cancelled.
- Paid $300 million in dividends to Edison International.

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

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

- Issued $600 million of first refunding mortgage bonds due in 2038. The proceeds were used to repay SCE's outstanding commercial paper of approximately $426 million and for general corporate purposes.

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

- Issued $400 million of 5.50% first and refunding mortgage bonds due in 2018. The proceeds were used to repay SCE's outstanding commercial paper of approximately $110 million and borrowings under the credit facility of $200 million, as well as for general corporate purposes.

- Paid $325 million in dividends to Edison International.

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

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

Net Cash Used by Investing Activities

Cash flows from investing activities are driven primarily by capital expenditures and funding of nuclear decommissioning trusts. Capital expenditures were $3.8 billion, $3.0 billion and $2.3 billion for 2010, 2009 and 2008, respectively, primarily related to transmission and distribution investments. Net purchases of nuclear decommissioning trust investments and other were $219 million, $199 million and $7 million for 2010, 2009 and 2008, respectively.

Contractual Obligations and Contingencies

Contractual Obligations

SCE's contractual obligations as of December 31, 2010, for the years 2011 through 2015 and thereafter are estimated below.

(in millions)	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
Long-term debt maturities and interest[1]	$ 15,631	$ 408	$ 817	$ 2,070	$ 12,336
Power purchase agreements[2]:					
Renewable energy contracts	13,676	340	1,062	1,267	11,007
Qualifying facility contracts	3,723	429	822	809	1,663
Other power purchase agreements	6,354	548	1,364	1,105	3,337
Other operating lease obligations[3]	528	61	116	96	255
Purchase obligations[4]:					
Fuel supply contract payments	1,584	260	367	309	648
Other commitments	34	5	13	13	3
Employee benefit plans contributions[5]	840	156	449	235	—
Total[6,7]	$ 42,370	$ 2,207	$ 5,010	$ 5,904	$ 29,249

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

2 Some of the power purchase agreements entered into with independent power producers are treated as operating leases and capital leases. At December 31, 2010, minimum operating lease payments for power purchase agreements were $740 million in 2011, $717 million in 2012, $761 million in 2013, $708 million in 2014, $693 million in 2015, and $8.7 billion for the thereafter period. At

December 31, 2010, minimum capital lease payments for power purchase agreements were $33 million in 2011, $71 million 2012, $131 million for 2013, $153 million for 2014, $154 million for 2015, and $2.5 billion for the thereafter period (amounts include executory costs and interest of $628 million and $1.2 billion, respectively). For further discussion, see "Item 8. SCE Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

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

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

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

6 At December 31, 2010, SCE had a total net liability recorded for uncertain tax positions of $335 million, which is excluded from the table. SCE cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the IRS.

7 The contractual obligations table does not include derivative obligations and asset retirement obligations, which are discussed in "Item 8. SCE Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities," and "Item 8. SCE Notes to Consolidated Financial Statements—Note 2. Property, Plant and Equipment," respectively.

Contingencies

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

Environmental Remediation

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

As of December 31, 2010, SCE identified 23 sites for remediation and recorded an estimated minimum liability of $50 million. SCE expects to recover 90% of its remediation costs at certain sites. See "Item 8. SCE Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies" for further discussion.

MARKET RISK EXPOSURES

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

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its financing and short-term investing activities used for liquidity purposes, to fund business operations and to fund capital investments. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. SCE's authorized return on common equity was 11.5% for 2010, 2009 and 2008, respectively, and has been authorized to remain at 11.5% through

December 2012 absent any future potential annual adjustment. SCE's authorized return on common equity is established in a multi-year cost of capital mechanism, which allows for annual adjustments if certain thresholds are reached. Variances in actual financing costs compared to authorized financing costs impact earnings either positively or negatively.

At December 31, 2010, the fair market value of SCE's long-term debt (including current portion of long-term debt) was $8.3 billion, compared to a carrying value of $7.6 billion. A 10% increase in market interest rates would have resulted in a $404 million decrease in the fair market value of SCE's long-term debt. A 10% decrease in market interest rates would have resulted in a $444 million increase in the fair market value of SCE's long-term debt.

Commodity Price Risk

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

SCE's hedging program reduces ratepayer exposure to variability in market prices. As part of this program, SCE enters into energy options, swaps, forward arrangements, tolling arrangements, and congestion revenue rights ("CRRs"). The transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. For further discussion on derivative instruments entered into to mitigate commodity price exposures, see "Item 8. SCE Notes to Consolidated Financial Statements Note 6. Derivative Instruments and Hedging Activities."

Fair Value of Derivative Instruments

SCE records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale exception. Derivative instrument fair values are marked to market at each reporting period. Any fair value changes are expected to be recovered from or refunded to customers through regulatory mechanisms and, therefore, SCE's fair value changes have no impact on purchased-power expense or earnings. SCE does not use hedge accounting for these transactions due to this regulatory accounting treatment. For further discussion on fair value measurements and the fair value hierarchy, see "Item 8. SCE Notes to Consolidated Financial Statements Note 4. Fair Value Measurements."

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

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

Credit Risk

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

Credit risk exposure from counterparties for power and gas trading activities is measured as the sum of net accounts receivable (accounts receivable less accounts payable) and the current fair value of net derivative assets (derivative assets less derivative liabilities) reflected on the consolidated balance sheets. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE's credit risk exposure from counterparties is based on a net exposure under these arrangements. SCE manages the credit risk on the portfolio for both rated and non-rated counterparties based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. As of December 31, 2010, the amount of balance sheet exposure as described above broken down by the credit ratings of SCE's counterparties, was as follows:

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

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

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

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

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

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 the consolidated financial statements. Management estimates and judgments are inherently uncertain and may differ significantly from actual results achieved. Management considers an accounting estimate to be critical if the estimate requires significant assumptions and changes in the estimate or, the use of alternative estimates, that could have a material impact on 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 ratemaking purposes. Using these factors, management has determined that existing regulatory assets and liabilities are probable of future recovery or settlement. This determination reflects the current regulatory climate in California and is subject to change in the future.

Effect if Different Assumption Used. Significant management judgment is required to evaluate the anticipated recovery of regulatory assets, the recognition of incentives and revenue subject to refund, as well as the anticipated cost of regulatory liabilities or penalties. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2010, the consolidated balance sheets included regulatory assets of $4.7 billion and regulatory liabilities of $5.3 billion. If different judgments were reached on recovery of costs and timing of income recognition, SCE's earnings and cash flows may vary from the amounts reported.

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. SCE 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 7. 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 2008 and 2007 for San Onofre and Palo Verde, respectively, which estimate that SCE will spend approximately $8.6 billion through 2053 to decommission its active nuclear facilities. Decommissioning cost estimates are updated in each Nuclear Decommissioning Triennial Proceeding. The current estimate is based on the following assumptions from the 2008 and 2007 site-specific study:

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

- Escalation Rates. Annual escalation rates are used to convert the decommissioning cost estimates in base year dollars to decommissioning cost estimates in future-year dollars. Escalation rates are primarily used for labor, material, equipment, and low level radioactive waste burial costs. SCE's current estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.8% to 6.9% (depending on the cost element) annually.

- Timing. Cost estimates are based on an assumption that decommissioning will commence promptly after the current NRC operating licensees expire. The operating licenses currently expire in 2022 for San Onofre Units 2 and 3, and in 2025, 2026 and 2027 for the Palo Verde units.

- Spent Fuel Dry Storage Costs. Cost estimates are based on an assumption that the DOE will begin to take spent fuel in 2015, and will remove the last spent fuel from the San Onofre and Palo Verde sites by 2051 and 2053, respectively. Costs for spent fuel monitoring are included until 2051 and 2053, respectively.

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

Effect if Different Assumptions Used. The ARO for decommissioning SCE's active nuclear facilities was $2.4 billion and $3.1 billion at December 31, 2010 and 2009, respectively. The ARO liability decrease in 2010 was mainly due to a decrease in escalation rates. Changes in the estimated costs or timing of decommissioning, or in the assumptions and judgments by management underlying these estimates, could cause material revisions to the estimated total cost to decommission these facilities which could have a material effect on the recorded liability and related regulatory asset. The following table illustrates the increase to the ARO and regulatory asset if the escalation rate was adjusted while leaving all other assumptions constant:

(in millions)	Increase to ARO and regulatory asset at December 31, 2010
Uniform increase in escalation rate of 25 basis points	$ 140

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, 2010, SCE's pension plans had a $3.7 billion benefit obligation and total expense for these plans was $97 million for 2010. As of December 31, 2010, SCE's PBOP plans had a $2.3 billion benefit obligation and total expense for these plans was $53 million for 2010. The following are critical assumptions used to determine expense for pension and other postretirement benefit for 2010:

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

[1] The discount rate enables 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 15.4%, 4.6% and 5.1% for the one-year, five-year and ten-year periods ended December 31, 2010, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 12.9%, 3.1%, and 3.2% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

[3] The health care cost trend rate gradually declines to 5.5% for 2016 and beyond.

Pension expense is recorded for SCE based on the amount funded to the trusts, as calculated using an actuarial method required for ratemaking purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with ratemaking methods and pension expense calculated in accordance with authoritative accounting guidance for pension is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2010, this cumulative difference amounted to a regulatory asset of $77 million, meaning that the accounting method has recognized more in expense than the ratemaking method since implementation of authoritative guidance for employers' accounting for pensions in 1987.

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 and PBOP plans have no plan assets.

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

A one percentage point increase in the discount rate would decrease the projected benefit obligation for pension by $304 million. A one percentage point decrease in the discount rate would increase the projected benefit obligation for pension by $326 million. A one percentage point increase in the expected rate of return on pension plan assets would decrease the expense by $27 million.

A one percentage point increase in the discount rate for PBOP would decrease the projected benefit obligation by $283 million. A one percentage point decrease in the discount rate for the PBOP would increase the projected benefit obligation by $330 million. A one percentage point increase in the expected rate of return on PBOP plan assets would decrease the expense by $15 million. Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2010 by $263 million and annual aggregate service and interest costs by $15 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2010 by $219 million and annual aggregate service and interest costs by $13 million.

Accounting for Contingencies, Guarantees and Indemnities

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

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 advisors, and the experience gained from similar cases. SCE provides disclosures for material contingencies when there is a reasonable possibility that a loss or an additional loss may be incurred. Some guarantees and indemnifications could have a significant financial impact under certain circumstances, and management also considers the probability of such circumstances occurring when estimating the fair value.

Effect if Different Assumptions Used. Actual amounts realized upon settlement of contingencies may be different than amounts recorded and disclosed and could have a significant impact on the liabilities, revenue and expenses recorded on the consolidated financial statements. In addition, for guarantees and indemnities actual results may differ from the amounts recorded and disclosed and could have a significant impact on SCE's consolidated financial statements. For a discussion of contingencies, guarantees and indemnities, see "Item 8. SCE Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

NEW ACCOUNTING GUIDANCE

New accounting guidance is 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 DISCLOSURE 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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southern California Edison Company (the "Company") and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule 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 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities and fair value disclosure principles as of January 1, 2010.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 28, 2011

(in millions)	Years ended December 31, 2010	2009	2008
Operating revenue	$ 9,983	$ 9,965	$ 11,248
Fuel	363	721	1,400
Purchased power	2,930	2,751	3,845
Operation and maintenance	3,291	3,154	3,013
Depreciation, decommissioning and amortization	1,273	1,178	1,114
Property and other taxes	263	244	232
Gain on sale of assets	(1)	(1)	(9)
Total operating expenses	8,119	8,047	9,595
Operating income	1,864	1,918	1,653
Interest income	7	11	22
Other income	141	160	101
Interest expense – net of amounts capitalized	(429)	(420)	(407)
Other expenses	(51)	(49)	(123)
Income before income taxes	1,532	1,620	1,246
Income tax expense	440	249	342
Net income	1,092	1,371	904
Less: Net income attributable to noncontrolling interests	—	94	170
Dividends on preferred and preference stock	52	51	51
Net income available for common stock	$ 1,040	$ 1,226	$ 683

Consolidated Statements of Comprehensive Income

(in millions)	Years ended December 31, 2010	2009	2008
Net income	$ 1,092	$ 1,371	$ 904
Other comprehensive income (loss), net of tax:			
Pension and postretirement benefits other than pensions:			
Net gain (loss) arising during period	(9)	(7)	2
Amortization of net (gain) loss included in net income	3	2	(2)
Prior service cost arising during the period	—	—	1
Comprehensive income	1,086	1,366	905
Less: Comprehensive income attributable to noncontrolling interests	—	94	170
Comprehensive income attributable to SCE	$ 1,086	$ 1,272	$ 735

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

(in millions)	December 31, 2010	December 31, 2009
ASSETS		
Cash and cash equivalents	$ 257	$ 462
Receivables, less allowances of $85 and $53 for uncollectible accounts at respective dates	715	719
Accrued unbilled revenue	442	347
Inventory	332	337
Prepaid taxes	168	33
Derivative assets	87	160
Regulatory assets	378	120
Other current assets	81	151
Total current assets	2,460	2,329
Nuclear decommissioning trusts	3,480	3,140
Other investments	68	67
Total investments	3,548	3,207
Utility property, plant and equipment, net	24,778	21,966
Nonutility property, plant and equipment, net	71	324
Total property, plant and equipment	24,849	22,290
Derivative assets	367	187
Regulatory assets	4,347	4,139
Other long-term assets	335	322
Total long-term assets	5,049	4,648
Total assets	$ 35,906	$ 32,474

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

(in millions, except share amounts)	December 31, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current portion of long-term debt	$ —	$ 250
Accounts payable	1,271	1,282
Accrued taxes	45	9
Accrued interest	169	162
Customer deposits	217	238
Derivative liabilities	212	102
Regulatory liabilities	738	367
Other current liabilities	663	637
Total current liabilities	3,315	3,047
Long-term debt	7,627	6,490
Deferred income taxes	4,829	3,651
Deferred investment tax credits	118	97
Customer advances	112	119
Derivative liabilities	449	496
Pensions and benefits	1,838	1,681
Asset retirement obligations	2,507	3,198
Regulatory liabilities	4,524	3,328
Other deferred credits and other long-term liabilities	1,380	1,652
Total deferred credits and other liabilities	15,757	14,222
Total liabilities	26,699	23,759
Commitments and contingencies (Note 9)		
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	572	551
Accumulated other comprehensive loss	(25)	(19)
Retained earnings	5,572	4,746
Total common shareholder's equity	8,287	7,446
Preferred and preference stock	920	920
Noncontrolling interests	—	349
Total equity	9,207	8,715
Total liabilities and equity	$ 35,906	$ 32,474

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

(in millions)	Years ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income	$ 1,092	$ 1,371	$ 904
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	1,273	1,178	1,114
Regulatory impacts of net nuclear decommissioning trust earnings (reflected in accumulated depreciation)	189	158	(10)
Other amortization	106	109	97
Stock-based compensation	17	13	18
Deferred income taxes and investment tax credits	973	574	131
Changes in operating assets and liabilities:			
Receivables	(25)	(9)	14
Inventory	(11)	28	(74)
Margin and collateral deposits – net of collateral received	2	63	(16)
Prepaid taxes	(135)	178	(66)
Other current assets	(101)	(29)	31
Accounts payable	(166)	43	(107)
Accrued taxes	36	(331)	298
Other current liabilities	118	26	(18)
Derivative assets and liabilities – net	(43)	(413)	634
Regulatory assets and liabilities – net	278	1,457	(2,946)
Other assets	(10)	48	275
Other liabilities	(207)	(395)	1,343
Net cash provided by operating activities	3,386	4,069	1,622
Cash flows from financing activities:			
Long-term debt issued	1,135	750	1,500
Long-term debt issuance costs	(16)	(11)	(20)
Long-term debt repaid	(259)	(154)	(3)
Bonds repurchased	—	(219)	(212)
Preferred stock redeemed	—	—	(7)
Short-term debt financing – net	—	(1,893)	1,393
Settlements of stock-based compensation – net	(5)	4	(15)
Distributions to noncontrolling interests	—	(125)	(236)
Dividends paid	(352)	(351)	(376)
Net cash provided (used) by financing activities	503	(1,999)	2,024
Cash flows from investing activities:			
Capital expenditures	(3,780)	(2,999)	(2,267)
Proceeds from sale of nuclear decommissioning trust investments	1,432	2,217	3,130
Purchases of nuclear decommissioning trust investments and other	(1,651)	(2,416)	(3,137)
Customer advances for construction and other investments	(3)	(21)	(13)
Effect of deconsolidation of variable interest entities	(92)	—	—
Net cash used by investing activities	(4,094)	(3,219)	(2,287)
Net increase (decrease) in cash and cash equivalents	(205)	(1,149)	1,359
Cash and cash equivalents, beginning of year	462	1,611	252
Cash and cash equivalents, end of year	$ 257	$ 462	$ 1,611

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

	Equity Attributable to SCE						
(in millions)	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, 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	—	—	—	(51)	—	—	(51)
Preferred stock redeemed, net of gain	—	2	—	—	(9)	—	(7)
Distributions to noncontrolling interests	—	—	—	—	—	(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	—	—	—	(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
Net income	—	—	—	1,092	—	—	1,092
Other comprehensive loss	—	—	(6)	—	—	—	(6)
Deconsolidation of variable interest entities (See Note 3)	—	—	—	—	—	(349)	(349)
Dividends declared on common stock	—	—	—	(200)	—	—	(200)
Dividends declared on preferred and preference stock	—	—	—	(52)	—	—	(52)
Stock-based compensation and other	—	4	—	(9)	—	—	(5)
Noncash stock-based compensation and other	—	17	—	(5)	—	—	12
Balance at December 31, 2010	$ 2,168	$ 572	$ (25)	$ 5,572	$ 920	$ —	$ 9,207

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to an approximately 50,000 square-mile area of southern California. SCE is a wholly-owned subsidiary of Edison International.

Basis of Presentation

The consolidated financial statements include SCE and its subsidiaries. Effective January 1, 2010, SCE deconsolidated four cogeneration projects in accordance with authoritative guidance for Variable Interest Entities ("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 ratemaking policies of the CPUC and the FERC. SCE applies authoritative guidance for rate-regulated enterprises to the portion of its operations in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of 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 require recording of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. SCE assesses, at the end of each reporting period, whether regulatory assets are probable of future recovery. See Note 14 for composition of regulatory assets and liabilities.

The preparation of financial statements in conformity with United States generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results could differ from those estimates. SCE's outstanding common stock is owned entirely by its parent company, Edison International.

Cash Equivalents

Cash equivalents included investments in money market funds totaling $243 million and $360 million at December 31, 2010 and 2009, respectively. Generally, the carrying value of cash equivalents equals the fair value, as all investments have maturities of three months or less.

SCE temporarily invests the ending daily cash balance in its primary disbursement accounts until required for check clearing. SCE reclassified $196 million and $224 million of checks issued against these accounts, but not yet paid by the financial institution, from cash to accounts payable at December 31, 2010 and 2009, respectively.

Allowance for Uncollectible Accounts

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

Inventory

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

Property, Plant and Equipment

Utility Property, Plant and Equipment

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

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

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

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	25 years to 70 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	46 years
Other plant	5 years to 60 years	22 years

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.1%, 4.2% and 4.3% for 2010, 2009 and 2008, respectively. Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for AROs.

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

AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction and is capitalized during certain plant construction. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. AFUDC – equity represents a method to compensate SCE for the estimated cost of equity used to finance utility plant additions and is recorded as part of construction in progress. AFUDC – equity was $100 million, $116 million and $54 million in 2010, 2009 and 2008, respectively. AFUDC – debt was $41 million, $32 million and $27 million in 2010, 2009 and 2008, respectively.

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

Major Maintenance

Certain plant facilities and equipment require periodic major maintenance. These costs are expensed as incurred.

Asset Retirement Obligation

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

(in millions)	2010	2009	2008
Beginning balance	$ 3,198	$ 3,007	$ 2,877
Accretion expense	195	186	175
Revisions[1]	(867)	6	(10)
Liabilities settled	(1)	(1)	(35)
Transfers in or out[2]	(18)	—	—
Ending balance	$ 2,507	$ 3,198	$ 3,007

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

[2] Transfers in or out consist of the deconsolidation of the Big 4 projects effective January 1, 2010. For further discussion, see Note 3.

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

Impairment of Long-Lived Assets

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

Leases

Power purchase agreements entered into by SCE contain leases as described under "Power Purchase Agreements" below. SCE has entered into a number of agreements to lease property and equipment in the normal course of business. Minimum lease payments under operating leases for property, plant and equipment are levelized (total minimum lease payments divided by the number of years of the lease) and recorded as rent expense over the terms of the leases. Lease payments in excess of the minimum are recorded as rent expense in the year incurred.

Capital leases are reported as long-term obligations on the consolidated balance sheets under "Other deferred credits and other long-term liabilities." As a rate regulated enterprise, SCE's capital lease amortization expense and interest expense are reflected in "Purchased power" on the consolidated statements of income.

Nuclear Decommissioning

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

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

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

Due to regulatory recovery of SCE's nuclear decommissioning expense, nuclear decommissioning activities do not affect SCE's earnings.

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

Deferred Financing Costs

Debt premium, discount and issuance expenses incurred in connection with obtaining financing are deferred and amortized on a straight-line basis as interest expense over the term of the related debt. Under CPUC ratemaking procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. SCE had unamortized losses on reacquired debt of $268 million and $287 million at December 31, 2010 and 2009, respectively, reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. SCE had unamortized debt issuance costs of $60 million and $50 million at December 31, 2010 and 2009, respectively, reflected in "Other long-term assets" on the consolidated balance sheets. Amortization of deferred financing costs charged to interest expense was $30 million, $27 million and $26 million in 2010, 2009 and 2008, respectively.

Revenue Recognition

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

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

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

Power Purchase Agreements

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

A power purchase agreement may also contain a lease for accounting purposes. This generally occurs when a power purchase agreement (signed or modified after June 30, 2003) designates a specific power plant in which the buyer purchases substantially all of the output and does not otherwise meet a fixed price per unit of output exception. SCE has a number of power purchase agreements that contain leases. SCE's recognition of lease expense conforms to the ratemaking treatment for SCE's recovery of the cost of electricity. See Note 9 for further discussion of SCE's power purchase agreements, including agreements that are classified as capital leases for accounting purposes.

A power purchase agreement that does not contain a lease may be classified as a derivative. SCE records its derivative instruments on its consolidated balance sheets at fair value unless they qualify for the normal purchase and sale exception, in which case, the power purchase agreement is classified as an executory contract. Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not meet the definition of a derivative or meet the normal purchase and sale exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a normal gas index, but the power is not generated with natural gas. These contracts are not eligible for the normal purchase and sale exception and are recorded as a derivative on the consolidated balance sheets at fair value. See Note 6 for further information on derivatives and hedging activities.

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

Derivative Instruments and Hedging Activities

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

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

Sales and Use Taxes

SCE bills certain sales and use taxes levied by state or local governments to its customers. Included in these sales and use taxes are franchise fees, which SCE pays to various municipalities (based on contracts with these municipalities) in order to operate within the limits of the municipality. SCE bills these franchise fees to its customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SCE's ability to collect from the customer, are accounted for on a gross basis and reflected in operating revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as operating revenue were $102 million, $102 million and $103 million for the years ended December 31, 2010, 2009 and 2008, respectively. When SCE acts as an agent and when the tax is not required to be remitted as not having been collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are for remission to the taxing authorities and are not recognized as operating revenue.

Stock-Based Compensation

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

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 is recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement.

Dividend Restrictions

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC sets an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the 48% authorized level on a 13-month weighted average basis. At December 31, 2010, SCE's 13-month weighted-average common equity component of total capitalization was 51% resulting in the capacity to pay $497 million in additional dividends.

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. SCE estimates its income taxes for each jurisdiction in which it operates. This involves estimating current period tax expense along with assessing temporary differences resulting from differing treatment of items (such as depreciation) for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within 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 "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.

Management evaluates its uncertain tax positions at each reporting date. Liabilities for uncertain tax positions are reflected in "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets.

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. SCE participates in the insurance program of Edison International, including property, general liability, workers' compensation and various other specialty policies. SCE's insurance premiums are generally based on SCE's share of risk related to each policy.

New Accounting Guidance

Accounting Guidance Adopted in 2010

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

This Financial Accounting Standards Board ("FASB") update changes how a company determines when an entity, that is insufficiently capitalized or is not controlled through voting (or similar rights), should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, its ability to direct the activities of the entity that most significantly impact the entity's economic performance and whether the entity has an obligation to absorb losses or the right to receive expected returns of the entity. This guidance requires a company to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. SCE adopted this guidance prospectively effective January 1, 2010. The impact of adopting this guidance resulted in the deconsolidation of projects related to four QF contracts. For further discussion, see Note 3.

Fair Value Measurements and Disclosures

This FASB accounting standards update provides for new disclosure requirements related to fair value measurements. The requirements, which SCE adopted effective January 1, 2010, include separate disclosure of significant transfers in and out of Levels 1 and 2 and the reasons for the transfers. The update also clarified existing disclosure requirements for the level of disaggregation, inputs and valuation techniques. Since this guidance impacts disclosures only, the adoption did not have an impact on SCE's consolidated results of operations, financial position or cash flows. In addition, effective January 1, 2011, the Level 3 reconciliation of fair value measurements using significant unobservable inputs should include gross rather than net information about purchases, sales, issuances and settlements. The guidance impacts disclosures only. For further discussion, see Note 4.

Note 2. Property, Plant and Equipment

Utility Property, Plant and Equipment

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

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

Jointly Owned Utility Projects

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

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

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

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

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

Nonutility Property, Plant and Equipment

As of December 31, 2009, nonutility property, plant and equipment was primarily composed of the VIEs which SCE deconsolidated as of January 1, 2010.

(in millions)	December 31, 2010	2009
Furniture and equipment	$ 3	$ 3
Building, plant and equipment	131	1,034
Land (including easements)	27	28
Construction in progress	10	3
	171	1,068
Accumulated provision for depreciation	(100)	(744)
Nonutility property – net	$ 71	$ 324

Note 3. Variable Interest Entities

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

Variable Interests in VIEs that are not Consolidated

Power Purchase Contracts

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

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

Big 4 Projects Consolidated Prior to 2010

SCE has variable interests in the Big 4 Projects through power contracts between SCE and the Big 4 Projects containing variable contract pricing provisions based on the price of natural gas. Prior to 2010, SCE had determined that it was the primary beneficiary of these four VIEs and, therefore, consolidated these projects. SCE prospectively deconsolidated the Big 4 Projects at January 1, 2010 since it does not control the commercial and operating activities of these projects. The deconsolidation did not result in a gain or loss.

SCE's consolidated balance sheet captions impacted by VIE activities prior to 2010 are presented below:

	December 31, 2009			
(in millions)	Electric Utility	VIEs	Eliminations	SCE
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 interests	—	349	—	349
Total liabilities and equity	32,076	430	(32)	32,474

SCE's consolidated statements of income impacted by VIE activities prior to 2010 are presented below:

(in millions)	Electric Utility	VIEs	Eliminations	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 interests	—	(94)	—	(94)
Dividends on preferred and preference stock	(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 interests	—	(170)	—	(170)
Dividends on preferred and preference stock	(51)	—	—	(51)
Net income available for common stock	$ 683	$ —	$ —	$ 683

Note 4. Fair Value Measurements

Recurring Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (referred to as an "exit price"). Fair value of an asset or liability should consider assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk.

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

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

	As of December 31, 2010				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$ 243	$ —	$ —	$ —	$ 243
Derivative contracts:					
Electricity	—	—	119	—	119
Natural gas	—	69	11	—	80
CRRs	—	—	137	—	137
Tolling	—	—	118	—	118
Subtotal of derivative contracts	—	69	385	—	454
Long-term disability plan	9	—	—	—	9
Nuclear decommissioning trusts					
Stocks[3]	2,029	—	—	—	2,029
Municipal bonds	—	790	—	—	790
Corporate bonds[4]	—	346	—	—	346
U.S. government and agency securities	215	73	—	—	288
Short-term investments, primarily cash equivalents[5]	1	31	—	—	32
Sub-total of nuclear decommissioning trusts	2,245	1,240	—	—	3,485
Total assets[6]	2,497	1,309	385	—	4,191
Liabilities at Fair Value					
Derivative contracts:					
Electricity	—	1	24	—	25
Natural gas	—	285	11	(4)	292
Tolling	—	—	344	—	344
Subtotal of derivative contracts	—	286	379	(4)	661
Total liabilities	—	286	379	(4)	661
Net assets	$ 2,497	$ 1,023	$ 6	$ 4	$ 3,530

(in millions)	As of December 31, 2009				
	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at Fair Value					
Money market funds[2]	$ 360	$ —	$ —	$ —	$ 360
Derivative contracts:					
Electricity	—	—	1	—	1
Natural gas	—	10	76	—	86
CRRs	—	—	217	—	217
Tolling	—	—	43	—	43
Subtotal of derivative contracts	—	10	337	—	347
Long-term disability plan	8	—	—	—	8
Nuclear decommissioning trusts					
Stocks[3]	1,772	—	—	—	1,772
Municipal bonds	—	634	—	—	634
Corporate bonds[4]	—	393	—	—	393
U.S. government and agency securities	240	68	—	—	308
Short-term investments, primarily cash equivalents[5]	1	14	—	—	15
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:					
Electricity	—	—	25	—	25
Natural gas	—	150	21	—	171
Tolling	—	—	402	—	402
Subtotal of derivative contracts	—	150	448	—	598
Total liabilities	—	150	448	—	598
Net assets (liabilities)	$ 2,381	$ 969	$ (111)	$ —	$ 3,239

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 sheets.

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

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

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

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

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

(in millions)	December 31, 2010	2009
Fair value of derivative contracts, net liabilities at beginning of period	$ (111)	$ (518)
Total realized/unrealized gains, net:		
Included in regulatory assets and liabilities[1]	58	312
Purchases and settlements, net	43	70
Transfers into Level 3	—	—
Transfers out of Level 3	16	25
Fair value of derivative contracts, net assets (liabilities) at end of period	$ 6	$ (111)
Change during the period in unrealized gains related to assets and liabilities held at the end of period	$ 130	$ 385

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

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

Valuation Techniques Used to Determine Fair Value

Level 1

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

Level 2

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

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

Level 3

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

For derivative contracts that trade infrequently (illiquid financial transmission rights and CRRs), changes in fair value are based on models forecasting the value of those contracts. The models' inputs are reviewed and the fair value is adjusted when it is concluded that a change in inputs would result in a new valuation that better reflects the fair value of those derivative contracts. For illiquid long-term power agreements, fair value is based upon the discounting of future electricity and natural gas prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit risk and market liquidity. Changes in fair value are based on changes to forward market prices, including forecasted prices for illiquid forward periods. The fair value of the majority of SCE's derivatives that are classified as Level 3 is determined using uncorroborated non-binding broker quotes and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Broker quotes are obtained from several brokers and compared against each other for reasonableness.

Nonperformance Risk

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

Nuclear Decommissioning Trusts

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

Fair Value of Long-Term Debt Recorded at Carrying Value

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

	December 31,			
	2010		2009	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 7,627	$ 8,285	$ 6,740	$ 7,202

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

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

Note 5. Debt and Credit Agreements

Long-Term Debt

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

(in millions)	December 31, 2010	December 31, 2009
First and refunding mortgage bonds:		
2014 – 2040 (4.15% to 6.05%)	$ 6,475	$ 5,475
Pollution-control bonds:		
2015 – 2035 (2.88% to 5.55%)	1,196	1,196
Bonds repurchased	(324)	(468)
Debentures and notes:		
2029 – 2053 (5.06% to 6.65%)	307	557
Long-term debt due within one year	—	(250)
Unamortized debt discount – net	(27)	(20)
Total	$ 7,627	$ 6,490

In 2009, SCE purchased two issues of its tax-exempt bonds totaling $219 million that were subject to remarketing and also converted those issues to a variable rate structure. In 2010, SCE reissued $144 million of these bonds and continues to hold the remaining $75 million of these bonds which remain outstanding and have not been retired or cancelled.

Long-term debt maturities for the next five years are: 2011 – zero; 2012 – zero; 2013 – zero; 2014 – $1.1 billion; and 2015 – $308 million.

Liens and Security Interests

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from certain pollution-control bonds issued by government agencies. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2010, SCE was in compliance with this debt covenant.

Credit Agreements

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

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

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

Note 6. Derivative Instruments and Hedging Activities

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

Commodity Price Risk

SCE is exposed to commodity price risk which represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's hedging program reduces ratepayer exposure to variability in market prices related to SCE's power and gas activities. As part of this program, SCE enters into energy options, swaps, forward arrangements, tolling arrangements and CRRs. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. SCE recovers its related hedging costs through the ERRA balancing account, and as a result, exposure to commodity price risk is not expected to impact earnings, but may impact cash flows.

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

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

Notional Volumes of Derivative Instruments

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

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

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

Fair Value of Derivative Instruments

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

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

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

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

Income Statement Impact of Derivative Instruments

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

The following table summarizes the components of economic hedging activity:

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

Contingent Features/Credit Related Exposure

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

Certain of these power contracts contain a provision that requires SCE to maintain an investment grade credit rating from each of the major credit rating agencies, referred to as a "credit-risk-related contingent feature." If SCE's credit rating were to fall below investment grade, SCE may be required to pay the derivative liability or post additional collateral. The aggregate fair value of all derivative liabilities with these credit-risk-related contingent features was $67 million and $91 million as of December 31, 2010 and 2009, respectively, for which SCE has posted $4 million collateral to its counterparties. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2010, SCE would be required to post an additional $2 million of collateral.

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

To manage credit risk, SCE looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary.

Margin and Collateral Deposits

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

	December 31,	
(in millions)	2010	2009
Collateral provided to counterparties:		
Offset against derivative liabilities	$ 4	$ —
Reflected in other current assets	5	6
Collateral received from counterparties:		
Reflected in other current liabilities	$ 60	$ 59

Note 7. Income Taxes

Current and Deferred Taxes

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

	Years ended December 31,		
(in millions)	2010	2009	2008
Current:			
Federal	$ (145)	$ (82)	$ 53
State	(71)	173	43
	(216)	91	96
Deferred:			
Federal	663	200	232
State	(7)	(42)	14
	656	158	246
Total	$ 440	$ 249	$ 342

The components of net accumulated deferred income tax liability are:

(in millions)	December 31, 2010	December 31, 2009
Deferred tax assets:		
Property and software related	$ 655	$ 630
Regulatory balancing accounts	230	229
Unrealized gains and losses	389	315
Pensions and PBOPs	176	213
Other	490	525
Total	$ 1,940	$ 1,912
Deferred tax liabilities:		
Property-related	$ 5,520	$ 4,371
Capitalized software costs	293	286
Regulatory balancing accounts	293	257
Unrealized gains and losses	389	315
Other	264	256
Total	$ 6,759	$ 5,485
Accumulated deferred income tax liability – net	$ 4,819	$ 3,573
Classification of accumulated deferred income taxes – net:		
Included in deferred credits and other liabilities	$ 4,829	$ 3,651
Included in current assets	$ 10	$ 78

Effective Tax Rate

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

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

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

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

The CPUC requires flow-through ratemaking treatment for the current tax benefit arising from certain property-related and other temporary differences which reverse over time. The accounting treatment for these temporary differences results in recording regulatory assets and liabilities for amounts that would otherwise be recorded to deferred income tax expense.

Global Settlement

Edison International and the IRS finalized the terms of a Global Settlement on May 5, 2009. The Global Settlement resolved 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. During 2010, SCE recorded a $95 million earnings benefit from the acceptance by the California Franchise Tax Board of the IRS tax positions finalized in 2009 and a revision to interest recorded on the federal Global Settlement. The net cash impacts of the Global Settlement, including the state impact, was $26 million and $875 million in 2010 and 2009, respectively.

Accounting for Uncertainty in Income Taxes

Authoritative guidance related to accounting for uncertainty in income taxes requires an enterprise to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. The guidance requires the disclosure of all unrecognized tax benefits, which includes both the reserves recorded for tax positions on filed tax returns and the unrecognized portion of affirmative claims.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits:

(in millions)	2010	2009	2008
Balance at January 1	$ 482	$ 2,066	$ 1,950
Tax positions taken during the current year			
Increases	47	14	111
Tax positions taken during a prior year			
Increases	140	200	162
Decreases	(272)	(212)	(157)
Decreases for settlements during the period	(68)	(1,586)	—
Balance at December 31	$ 329	$ 482	$ 2,066

Unrecognized tax benefits were reduced by $68 million during 2010 related to the California Franchise Tax Board's acceptance of the federal Global Settlement as discussed above and $1.6 billion during 2009 primarily due to completion of the federal Global Settlement as discussed above.

Edison International's federal income tax returns and its California combined franchise tax returns are currently open for years subsequent to 2002. In addition, specific California refund claims made by Edison International for years 1991 through 2002 remain subject to audit. The IRS examination phase of tax years 2003 through 2006 was completed in the fourth quarter of 2010, which included a proposed adjustment to disallow a component of SCE's repair allowance deduction. Edison International disagrees with the proposed adjustment and filed a protest with the IRS on January 28, 2011. If sustained, the proposed disallowance would result in a federal tax payment of $90 million, including interest.

During the fourth quarter of 2010, SCE made a tax and interest deposit of $131 million primarily related to rollforward issues included in the Global Settlement that subsequently impacted tax years 2003 through 2006.

As of December 31, 2010 and 2009, respectively, if recognized, $225 million and $179 million of the unrecognized tax benefits would impact the effective tax rate.

Accrued Interest and Penalties

The total amount of accrued interest and penalties related to SCE's income tax liabilities was $61 million and $79 million as of December 31, 2010 and 2009, respectively.

The net after-tax interest and penalties recognized in income tax expense was a benefit of $80 million and $279 million in 2010 and 2009, respectively, compared to an expense of $14 million in 2008.

Note 8. 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 $76 million in 2010, $70 million in 2009 and $65 million in 2008.

Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

Noncontributory defined benefit pension plans (some with cash balance features) cover most employees meeting minimum service requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking. The expected contributions (all by the employer) are approximately $102 million for the year ending December 31, 2011. Annual contributions made to most of SCE's pension plans are recovered through CPUC-approved regulatory mechanisms. Annual contributions to these plans are expected to be, at a minimum, equal to the related annual expense.

Volatile market conditions have affected the value of 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 and 2010 partially offset the impacts of the 2008 market conditions.

Changes in the plan's funded status also affect the assets and liabilities recorded on the consolidated balance sheets. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts. The Pension Protection Act of 2006 established new minimum funding standards and placed various restrictions on underfunded plans.

Information on plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31, 2010	2009
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 3,389	$ 3,175
Service cost	132	107
Interest cost	193	191
Amendments	5	21
Actuarial loss	185	57
Benefits paid	(172)	(162)
Projected benefit obligation at end of year	$ 3,732	$ 3,389
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,726	$ 2,238
Actual return on plan assets	414	551
Employer contributions	98	99
Benefits paid	(172)	(162)
Fair value of plan assets at end of year	$ 3,066	$ 2,726
Funded status at end of year	$ (666)	$ (663)
Amounts recognized in the consolidated balance sheets:		
Current liabilities	$ (6)	$ (5)
Long-term liabilities	(660)	(658)
	$ (666)	$ (663)
Amounts recognized in accumulated other comprehensive loss consist of:		
Net loss	$ 42	$ 31
Amounts recognized as a regulatory asset:		
Prior service cost	$ 40	$ 42
Net loss	500	556
	$ 540	$ 598
Total not yet recognized as expense	$ 582	$ 629
Accumulated benefit obligation at end of year	$ 3,436	$ 3,086
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 3,732	$ 3,389
Accumulated benefit obligation	3,436	3,086
Fair value of plan assets	3,066	2,726
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	5.25%	6.0%
Rate of compensation increase	5.0%	5.0%

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years ended December 31, 2010	2009	2008
Service cost	$ 132	$ 107	$ 104
Interest cost	193	191	184
Expected return on plan assets	(201)	(162)	(249)
Amortization of prior service cost	8	11	17
Amortization of net loss	17	54	3
Expense under accounting standards	$ 149	$ 201	$ 59
Regulatory adjustment—deferred	(52)	(94)	(5)
Total expense recognized	$ 97	$ 107	$ 54

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

(in millions)	Years ended December 31, 2010	2009	2008
Net loss (gain)	$ 15	$ 11	$ (2)
Amortization of net loss	(4)	(4)	(3)
Total recognized in other comprehensive (income) loss	$ 11	$ 7	$ (5)
Total recognized in expense and other comprehensive income	$ 107	$ 114	$ 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 that will be amortized to expense in 2011 are $17 million and $7 million, respectively; $6 million of the net loss is expected to be reclassified from accumulated other comprehensive income.

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

	Years ended December 31, 2010	2009	2008
Discount rate	6.0%	6.25%	6.25%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected 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,
2011	$ 262
2012	271
2013	278
2014	285
2015	296
2016 – 2020	1,542

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 $54 million for the year ending December 31, 2011. Annual contributions made to SCE plans are recovered through CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to the total annual expense for these plans.

Volatile market conditions have affected the value of Edison International's trusts established to fund its future other postretirement benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trust declined 33% during 2008. This reduction in the value of plan assets resulted in an increase in the plan's underfunded status and will also result in increased future expense and increased future contributions. Improved market conditions in 2009 and 2010 partially offset the impacts of the 2008 market conditions.

Changes in the plan's funded status affect the assets and liabilities recorded on SCE's consolidated balance sheets. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to this trust.

Information on plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31, 2010	2009
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,011	$ 2,247
Service cost	34	28
Interest cost	121	116
Amendments	12	(63)
Actuarial loss (gain)	203	(233)
Plan participants' contributions	17	15
Medicare Part D subsidy received	5	5
Benefits paid	(108)	(104)
Benefit obligation at end of year	$ 2,295	$ 2,011
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,459	$ 1,212
Actual return on assets	175	256
Employer contributions	58	75
Plan participants' contributions	17	15
Medicare Part D subsidy received	5	5
Benefits paid	(108)	(104)
Fair value of plan assets at end of year	$ 1,606	$ 1,459
Fund status at end of year	$ (689)	$ (552)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	$ (17)	$ (16)
Long-term liabilities	(672)	(536)
	$ (689)	$ (552)
Amounts recognized as a regulatory asset (liability):		
Prior service credit	$ (161)	$ (209)
Net loss	718	625
Total not yet recognized as expense	$ 557	$ 416
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	5.5%	6.0%
Assumed health care cost trend rates:		
Rate assumed for following year	9.75%	8.25%
Ultimate rate	5.5%	5.5%
Year ultimate rate reached	2019	2016

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

	Years ended December 31,		
(in millions)	2010	2009	2008
Service cost	$ 34	$ 28	$ 38
Interest cost	121	116	130
Expected return on plan assets	(100)	(81)	(122)
Amortization of prior service credit	(37)	(32)	(29)
Amortization of net loss	35	44	14
Total expense	$ 53	$ 75	$ 31

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 2011 are $36 million and $(36) million, respectively.

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

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

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2010 by $263 million and annual aggregate service and interest costs by $15 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2010 by $219 million and annual aggregate service and interest costs by $13 million.

The following benefit payments are expected to be paid:

	Years ended December 31,	
(in millions)	Before Subsidy[1]	Net
2011	$ 93	$ 88
2012	108	102
2013	118	111
2014	126	119
2015	133	125
2016 – 2020	796	742

[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. Target allocations for pension plan assets are 30% for U.S. equities, 16% for non-U.S. equities, 35% for fixed income, 15% for opportunistic and/or alternative investments and 4% for other investments. Target allocations for PBOP plan assets are 41% for U.S. equities, 17% for non-U.S. equities, 34% for fixed income, 7% for opportunistic and/or alternative investments, and 1% for other investments. Edison International employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is managed through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. Edison International also monitors the stability of its investment managers' organizations.

Allowable investment types include:

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

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

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

Opportunistic, Alternative and Other Investments:

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

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

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

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

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

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

Capital Markets Return Forecasts

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

Fair Value of Plan Assets

The PBOP Plan and the Southern California Edison Company Retirement Plan Trust (Master Trust) assets include investments in equity securities, U.S. treasury securities, other fixed-income securities, common/collective funds, mutual funds, other investment entities, foreign exchange and interest rate contracts, and partnership/joint ventures. Equity securities, U.S. treasury securities, mutual and money market funds are classified as Level 1 as fair value is determined by observable, unadjusted quoted market prices in active or highly liquid and transparent markets. Common/collective funds are valued at the net asset value (NAV) of shares held. Although common/collective funds are determined by observable prices, they are classified as Level 2 because they trade in markets that are less active and transparent. The fair value of the underlying investments in equity mutual funds and equity common/collective funds are based upon stock-exchange prices. The fair value of the underlying investments in fixed-income common/collective funds, fixed-income mutual funds and other fixed income securities including municipal bonds are based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information. Foreign exchange and interest rate contracts are classified as Level 2 because the values are based on observable prices but are not traded on an exchange. Futures contracts trade on an exchange and therefore are classified as Level 1. One of the partnerships is classified as Level 2 since this investment can be readily redeemed at NAV and the underlying investments are liquid publicly traded fixed-income securities which have observable prices. The remaining partnerships/joint ventures are classified as Level 3 because fair value is determined primarily based upon management estimates of future cash flows. Other investment entities are valued similarly to common collective funds and are therefore classified as Level 2. The Level 1 registered investment companies are either mutual or money market funds. The remaining funds in this category are readily redeemable at NAV and classified as Level 2 and are discussed further at footnote 6 to the pension plan master trust investments table below.

Pension Plan

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

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks[1]	$ 786	$ —	$ —	$ 786
Common/collective funds[2]	—	600	—	600
Corporate bonds[3]	—	555	—	555
Partnerships/joint ventures[4]	—	155	345	500
U.S. government and agency securities[5]	84	316	—	400
Registered investment companies[6]	84	169	—	253
Other investment entities[7]	—	159	—	159
Interest-bearing cash	5	—	—	5
Other	2	30	—	32
Total	$ 961	$ 1,984	$ 345	$ 3,290
Receivables and payables, net				(55)
Net plan assets available for benefits				$ 3,235
SCE's share of net plan assets				$ 3,066

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

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

[1] Corporate stocks are diversified. For 2010 and 2009, respectively, performance is primarily benchmarked against the Russell Indexes (63% and 61%) and Morgan Stanley Capital International (MSCI) index (37% and 39%).

[2] At December 31, 2010 and 2009, respectively, the common/collective assets were invested in equity index funds that seek to track performance of the Standard and Poor's (S&P 500) Index (29% and 33%), Russell 200 and Russell 1000 indexes (28% and 26%) and the MSCI Europe, Australasia and Far East (EAFE) Index (11% and 10%). A non-index U.S. equity fund representing 23% and 20% of this category as of December 31, 2010 and 2009, respectively, is actively managed. Another fund representing 8% and 7% of this category as of December 31, 2010 and 2009, respectively, is a global asset allocation fund.

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

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

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

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

[7] At December 31, 2010 and 2009, respectively, 57% and 64% of the other investment entities balance is invested in emerging market equity securities. At December 31, 2010 and 2009, respectively, about 24% and 17% of the assets in this category are invested in domestic mortgage backed securities. Most of the remaining funds invest in below grade fixed income securities including foreign issuers.

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

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

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

Postretirement Benefits Other than Pensions

The following table sets forth the PBOP Plan's financial assets that were accounted for at fair value as of December 31, 2010 by asset class and level within the fair value hierarchy:

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

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

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

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

2 Corporate stock performance is primarily benchmarked against the Russell Indexes (65% and 67%) and the MSCI All Country World (ACWI) index (35% and 33%) for 2010 and 2009, respectively.

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

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

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

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

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

At December 31, 2010 and 2009, approximately 67% and 76%, respectively, of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

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

(in millions)	2010	2009
Fair value, net at beginning of period	$ 49	$ 12
Actual return on plan assets		
Relating to assets still held at end of period	14	12
Relating to assets sold during the period	—	1
Purchases and dispositions, net	29	27
Transfers in and /or out of Level 3	—	(3)
Fair value, net at end of period	$ 92	$ 49

Stock-Based Compensation

Edison International maintains a shareholder approved incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. The maximum number of shares of Edison International's common stock authorized to be issued or transferred pursuant to awards under the 2007 Performance Incentive Plan, as amended in 2009, is 21.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued ("carry-over shares"). As of December 31, 2010, Edison International had approximately 9 million shares remaining for future issuance under its stock-based compensation plans.

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

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

	Years ended December 31,		
	2010	2009	2008
Expected terms (in years)	7.3	7.4	7.4
Risk-free interest rate	2.0% – 3.2%	2.8% – 3.5%	2.6% – 3.8%
Expected dividend yield	3.3% – 4.0%	3.6% – 5.0%	2.3% – 3.9%
Weighted-average expected dividend yield	3.8%	4.9%	2.5%
Expected volatility	18.8% – 19.8%	20% – 21%	17% – 19%
Weighted-average volatility	19.8%	20.6%	17.3%

The expected term represents the period of time for which the options are expected to be outstanding and is primarily based on historical exercise and post-vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a zero coupon U.S. Treasury issued STRIPS (separate trading of registered interest and principal of securities) whose maturity equals the option's expected term on the measurement date. Expected volatility is based on the historical volatility of Edison International's common stock for the lesser of 1) the period from January 1, 2003 through the last month-end prior to the grant date or 2) the length of the option's expected term. The volatility period used was 87 months, 84 months and 72 months at December 31, 2010, 2009 and 2008, respectively.

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

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2009	8,749,015	$ 31.91		
Granted	2,199,716	$ 33.38		
Expired	(10,587)	$ 49.03		
Forfeited	(145,516)	$ 31.32		
Exercised	(756,446)	$ 22.94		
Affiliate transfers – net	28,554	$ 36.33		
Outstanding at December 31, 2010	10,064,736	$ 32.86	6.32	
Vested and expected to vest at December 31, 2010	9,815,717	$ 32.88	6.26	80,399,824
Exercisable at December 31, 2010	5,283,358	$ 33.30	4.55	44,826,129

At December 31, 2010, 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.

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2008, March 2009 and March 2010, and vest at the end of December 2010, 2011 and 2012, respectively. Performance shares awarded contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's total shareholder return relative to the total shareholder return of a specified group of peer companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Edison International also has discretion to pay certain dividend equivalents in Edison International common stock. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares that can be settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants.

The fair value of performance shares is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires various assumptions noted in the following table.

	Years ended December 31,		
	2010	2009	2008
Equity awards			
Grant date risk-free interest rate	1.3%	1.3%	3.9%
Grant date expected volatility	21.6%	21.4%	17.4%
Liability awards[1]			
Expected volatility	20.6%	21.9%	19.2%
Risk-free interest rate:			
2010 awards	0.6%	—	—
2009 awards	0.3%	1.1%	—
2008 awards	—	0.5%	0.8%

[1] The portion of performance shares classified as share-based liability awards are revalued at each reporting period.

The risk-free interest rate is based on the daily spot rate on the grant or valuation date on U.S. Treasury zero coupon issue or STRIPS with terms nearest to the remaining term of the performance shares and is used as a proxy for the expected return for the specified group of peer companies. Expected volatility is based on the historical volatility of Edison International's (and the specified group of peer companies') common stock for the most recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

At December 31, 2010, there was $2 million (based on the December 31, 2010 fair value of performance shares classified as equity awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of approximately two years.

The following is a summary of the status of Edison International nonvested performance shares:

	Equity Awards		Liability Awards	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Fair Value
Nonvested at December 31, 2009	172,604	$ 36.65	172,604	
Granted	83,306	$ 32.19	83,306	
Forfeited	(36,797)	$ 54.51	(36,797)	
Affiliate transfers – net	791	$ 41.62	791	
Nonvested at December 31, 2010	219,904	$ 32.15	219,904	$ 37.68

The current portion of nonvested performance shares classified as liability awards is reflected in "Other current liabilities" and the long-term portion is reflected in "Pensions and benefits" on the consolidated balance sheets.

Restricted Stock Units

Restricted stock units were awarded to executives in March 2008, March 2009 and March 2010 and vest and become payable in January 2011, 2012 and 2013, respectively. Each restricted stock unit awarded is a contractual right to receive one share of Edison International common stock, if vesting requirements are satisfied. Restricted stock units awarded contain dividend equivalent reinvestment rights. An additional number of restricted stock units will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's restricted stock units is dependent upon continuous service through the end of the three-calendar-year-plus-two-days vesting period. Vesting is subject to a pro-rated adjustment for employees who are terminated under certain circumstances or retire. Cash awards are substituted to the extent necessary to pay tax withholding or any government levies.

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

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2009	238,835	$ 32.87
Granted	160,684	33.38
Forfeited	(9,292)	33.47
Paid Out	(5,619)	37.68
Affiliate transfers – net	1,269	46.82
Nonvested at December 31, 2010	385,877	$ 32.90

The fair value for each restricted stock unit awarded is determined as the closing price of Edison International common stock on the grant date.

Compensation expense related to these shares, which is based on the grant-date fair value, is recognized ratably over the requisite service period, except for awards whose holders become eligible for retirement vesting during the service period, in which case recognition is accelerated into the year the holders become eligible for retirement vesting. At December 31, 2010, there was $4 million of total unrecognized compensation cost related to restricted stock units, net of expected forfeitures, which is expected to be recognized as follows: $3 million in 2011 and $1 million in 2012.

Supplemental Data on Stock Based Compensation

(in millions, except per award amounts)	Years ended December 31, 2010	2009	2008
Stock Based Compensation Expense[1]			
Stock options	$ 10	$ 8	$ 12
Performance shares	6	3	—
Restricted stock units	5	3	2
Other	6	6	1
Total stock based compensation expense	$ 27	$ 20	$ 15
Income tax benefits related to stock compensation expense	$ 11	$ 8	$ 6
Excess tax benefits[2]	4	7	4
Stock options			
Weighted average grant date fair value per option granted	$ 4.87	$ 3.06	$ 10.19
Fair value of options vested	11	8	12
Cash used to purchase shares to settle options	27	9	30
Cash from participants to exercise stock options	18	6	17
Value of options exercised	9	3	13
Tax benefits from options exercised	4	1	5
Performance Shares Classified as Equity Awards			
Weighted average grant date fair value per share granted	$ 32.19	$ 21.56	$ 55.55
Fair value of shares vested	3	1	2
Value of shares settled	—	—	5
Tax benefits realized from settlement of awards	—	—	2
Performance Shares Classified as Liability Awards			
Value of shares settled	$ —	$ —	$ 6
Tax benefits realized from settlement of awards	—	—	2
Restricted Stock units[3]			
Weighted average grant date fair value per unit granted	$ 33.38	$ 25.32	$ 49.83

1 Reflected in "Operations and maintenance" on the consolidated statements of income.

2 Reflected in "Settlements of stock based compensation – net" in the financing section of the consolidated statements of cash flows.

3 The value of restricted stock units settled was less than $1 million for 2010, 2009 and 2008.

Note 9. Commitments and Contingencies

Third-Party Power Purchase Agreements

SCE enters into various agreements to purchase power and electric capacity, including:

- *Renewable Energy Contracts* – California law requires retail sellers of electricity to comply with an RPS by purchasing renewable energy (such as biomass, small hydroelectric, wind, solar, and geothermal energy), so that the amount of electricity delivered from eligible renewable resources equals at least 20% of their total retail sales by the end of 2010 or such later date as is permitted by flexible compliance rules. Renewable contract payments generally consist of payments based on a fixed price per megawatt hour. As of December 31, 2010, SCE had 97 renewable energy contracts that were approved by the CPUC and met critical contract provisions which expire at various dates between 2011 and 2033.

- *Qualifying Facility Power Purchase Agreements* – Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities are required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities and qualifying small power production facilities

(“QFs”). As of December 31, 2010, SCE had 170 QF contracts which expire at various dates between 2011 and 2026.

- *Other Power Purchase Agreements* – In accordance with the SCE’s CPUC-approved long-term procurement plans, SCE has entered into capacity agreements with third parties, including 14 tolling arrangements, 47 power call options and 106 resource adequacy contracts. SCE’s obligations under a portion of these agreements are limited to payments for the availability of such resources.

At December 31, 2010, the undiscounted future expected payments for power purchase agreements that have been approved by the CPUC and have completed major milestones for construction were as follows:

(in millions)	Renewable Energy Contracts	QF Power Purchase Agreements	Other Purchase Agreements
2011	$ 340	$ 429	$ 548
2012	494	411	616
2013	568	411	748
2014	633	410	638
2015	634	399	468
Thereafter	11,007	1,663	3,336
Total future commitments	$ 13,676	$ 3,723	$ 6,354

Some of the power purchase agreements that SCE entered into with independent power producers are treated as operating and capital leases. The following table shows the future fixed capacity payments due under the contracts that are treated as operating and capital leases (these amounts are also included in the table above). The fixed capacity payments for capital leases are discounted to their present value in the table below using SCE’s incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	Operating Leases	Capital Leases
2011	$ 740	$ 33
2012	717	71
2013	761	131
2014	708	153
2015	693	154
Thereafter	8,741	2,479
Total future commitments	$ 12,360	$ 3,021
Amount representing executory costs		(628)
Amount representing interest		(1,168)
Net commitments		$ 1,225

Operating lease expense for these power purchase agreements was $350 million in 2010, $358 million in 2009 and $328 million in 2008. The timing of SCE’s recognition of the lease expense conforms to ratemaking treatment for SCE’s recovery of the cost of electricity. The amounts above do not include payments related to CDWR purchases for the benefit of SCE’s customers, as SCE is acting as an agent for the CDWR.

At December 31, 2010 and 2009, net capital leases reflected in “Utility plant” on the consolidated balance sheets were $227 million and $235 million, including amortization of $22 million and $13 million, respectively. SCE had $5 million and $8 million included in “Other current liabilities” and $222 million and $227 million included in “Other deferred credits and other liabilities,” representing the present value of the fixed capacity payments due under these contracts recorded on the consolidated balance sheets at December 31, 2010 and 2009, respectively.

Both capital and operating leases have varying terms, provisions and expiration dates. The contingent rentals for capital leases were less than $1 million for both 2010 and 2009.

Other Lease Commitments

The following summarizes the estimated minimum future commitments for noncancelable other operating leases (excluding power purchase agreements discussed above):

(in millions)	Operating Leases – Other
2011	$ 61
2012	60
2013	56
2014	51
2015	45
Thereafter	255
Total future commitments	$ 528

Operating lease expense for other leases (primarily related to vehicles, office space and other equipment) were $62 million in 2010, $47 million in 2009 and $47 million in 2008. Operating leases have varying terms, provisions and expiration dates.

Nuclear Decommissioning Commitment

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The recorded liability to decommission SCE's nuclear power facilities is $2.4 billion as of December 31, 2010, based on site-specific studies performed in 2008 for San Onofre and 2007 for Palo Verde. Changes in the estimated costs, timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE estimates that it will spend approximately $8.6 billion through 2053 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.8% to 6.9% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $23 million per year. Contributions received in prior years were approximately $46 million. SCE estimates annual after-tax earnings on the decommissioning funds of 4.2% to 5.7%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates in the future. If the assumed return on trust assets is greater than estimated, funding amounts may be reduced through future decommissioning proceedings.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds and are subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability of $63 million at December 31, 2010. Total expenditures for the decommissioning of San Onofre Unit 1 were $596 million from the beginning of the project in 1998 through December 31, 2010.

Decommissioning expense under the ratemaking method was $30 million in 2010 and $46 million in both 2009 and 2008. The ARO for decommissioning SCE's active nuclear facilities was $2.4 billion and $3.1 billion at December 31, 2010 and 2009, respectively. See Note 4 and Note 15 for discussion on the nuclear decommissioning trusts.

Other Commitments

Certain other commitments for the years 2011 through 2015 are estimated below:

(in millions)	2011	2012	2013	2014	2015
Fuel supply contracts	$ 260	$ 178	$ 189	$ 143	$ 166
Other contractual obligations	5	7	7	7	7

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.

Indemnities

Indemnity Provided as Part of the Acquisition of Mountainview

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

Mountainview Filter Cake Indemnity

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

Other 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.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 against SCE, among other defendants, arising out of the coal supply agreement for Mohave. Subsequently, the Hopi Tribe was added as an additional plaintiff. As amended in April 2010, the Navajo Nation's complaint asserts claims for, among other things, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, plus interest thereon, and punitive damages of not less than $1 billion. No trial date has been set for this litigation. In April 2009, in a related case filed in December 1993 against the U.S. Government, the U.S. Supreme Court found that the Navajo Nation did not have a claim for compensation. In October 2010, the Hopi Tribe settled all of its claims and the remaining parties agreed to engage in mediation. SCE cannot predict the outcome of the Navajo Nation's complaint against SCE.

Environmental Remediation

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 (reflected in "Other long-term liabilities") at undiscounted amounts as timing of cash flows is uncertain.

As of December 31, 2010, SCE's recorded estimated minimum liability to remediate its 23 identified material sites (sites in which the upper end of the range of costs is at least $1 million) was $50 million, of which $20 million was related to San Onofre. In addition to its identified material sites SCE also has 34 immaterial sites for which the total recorded liability was $4 million. 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 at these identified material sites and immaterial sites could exceed its recorded liability by up to $200 million and $7 million, respectively. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover 90% of its environmental remediation costs at certain sites, representing $29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE recovers 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $51 million for its estimated minimum environmental cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $3 million to $18 million. Recorded costs were

$17 million, $11 million and $29 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Based on currently available information, 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.

2010 FERC Rate Case

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

Nuclear Insurance

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

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

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by entities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately $43 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the Department of Energy ("DOE") is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. Currently, both San Onofre and Palo Verde have interim storage for spent nuclear fuel on site sufficient for the current license period.

In January 2004, SCE, as operating agent of San Onofre, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. In June 2010, the United States Court of Federal Claims issued a decision granting SCE damages of approximately $142 million to recover costs incurred through December 31, 2005, which has been appealed by the DOE. Additional legal action would be necessary to recover damages incurred after that date. Any damages recovered would be returned to SCE ratepayers or used to offset past or future fuel decommissioning or storage costs for the benefit of ratepayers.

Note 10. Regulatory and Environmental Developments

Regulatory Developments

Wildfire Insurance Issues

Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. On September 1, 2010, SCE's parent, Edison International, renewed its insurance coverage, which included coverage for SCE's wildfire liabilities up to a $610 million limit (with an increased self-insured retention of $10 million per wildfire occurrence). Various coverage limitations within the policies that make up the insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy period (September 1, 2010 to August 31, 2011). SCE may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.

Environmental Developments

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 the environmental impact of past operations.

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

Greenhouse Gas Regulation

There have been a number of federal and state legislative and regulatory initiatives to reduce greenhouse gas ("GHG") emissions. Any climate change regulation or other legal obligation that would require substantial reductions in GHG emissions or that would impose additional costs or charges for GHG emissions could significantly increase the cost of generating electricity from fossil fuels as well as the cost of purchased power, which could adversely affect SCE's business. In the case of utilities, like SCE, these costs are generally borne by customers.

Significant developments include the following:

- In December 2009, the US EPA issued a final finding that certain GHGs, including carbon dioxide, threaten the public health and welfare. The US EPA has issued a proposed rule, known as the "GHG tailoring rule," which generally subjects newly constructed sources of GHG emissions and newly modified existing major sources to the Prevention of Significant Deterioration air permitting program (and later, the Title V permitting program), beginning in January 2011. The current program, which applies to only new or newly modified sources, is not expected to have an immediate effect on SCE's existing generating plants. However, regulation of GHG emissions pursuant to this program could affect efforts to modify SCE's facilities in the future, and could subject new capital projects to additional permitting and pollution control requirements that could delay such projects.

- Under a pending court settlement, the US EPA will propose performance standards for GHG emissions from new and modified power plants, and emissions guidelines for existing power plants, in July 2011, and will finalize such regulations by May 2012, with compliance dates expected to be in 2015 or 2016. The specific requirements will not be known until the regulations are finalized.

- In December 2010, the California Air Resources Board ("CARB") finalized regulations establishing a California cap-and-trade program, which include revisions to CARB's mandatory GHG emissions reporting regulation. The regulations and the cap-and-trade program itself are being challenged by various citizens' groups under the California Environmental Quality Act.

- In December 2010, the Supreme Court agreed to hear a case in which an appellate court found that judicial remedies for nuisance allegedly caused by GHG emissions were appropriate. The Supreme Court's decision may resolve the question of whether or not this type of litigation presents questions capable of judicial resolution or political questions that should be resolved by elected officials.

Clean Water Act

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

A new rule could have a material impact on SCE's operations but SCE cannot determine the financial impact until the final compliance criteria have been published. Significant capital expenditures may be required.

Once-Through Cooling

California has a US EPA-approved program to issue individual or group (general) permits for the regulation of Clean Water Act discharges. California also regulates certain discharges not regulated by the US EPA. In May 2010, the California State Water Resources Board issued a final policy, which establishes closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like San Onofre and many of the existing fossil-fueled power plants along the California coast. The final policy, which took effect on October 1, 2010, requires an independent engineering study to be completed prior to the fourth quarter of 2013 regarding the feasibility of compliance by California's two coastal nuclear power plants. Depending on the results of the study, the required compliance may result in significant capital expenditures at San Onofre and may affect its operations. The policy could adversely affect California's nineteen once-through cooled power plants, which provide over 21,000 MW of combined, in-state generation capacity, including over 9,100 MW of capacity interconnected within SCE's service territory. The policy may also significantly impact SCE's ability to procure generating capacity from fossil-fueled plants that use ocean water in once-through cooling systems, system reliability and the cost of electricity to the extent other coastal power plants in California are forced to shut down or limit operations.

Note 11. Accumulated Other Comprehensive Loss

SCE's accumulated other comprehensive income consists of:

(in millions)	Pension and PBOP – Net Loss	Pension and PBOP – Prior Service Cost	Accumulated Other Comprehensive Loss
Balance at December 31, 2008	$ (13)	$ (1)	$ (14)
Change for 2009	(5)	—	(5)
Balance at December 31, 2009	(18)	(1)	(19)
Change for 2010	(7)	1	(6)
Balance at December 31, 2010	$ (25)	$ —	$ (25)

Note 12. Supplemental Cash Flows Information

SCE's supplemental cash flows information is:

(in millions)	Years ended December 31, 2010	2009	2008
Cash payments(receipts) for interest and taxes:			
Interest – net of amounts capitalized	$ 369	$ 352	$ 303
Tax payments (refunds) – net	(127)	(658)	251
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	$ (378)	$ —	$ —
Pollution-control bonds issued	378	—	—
Details of capital lease obligations:			
Capital lease purchased	$ —	$ (223)	$ —
Capital lease obligation issued	—	223	—
Deconsolidation of variable interest entities:			
Assets other than cash	$ 306	$ —	$ —
Liabilities and noncontrolling interests	(398)	—	—
Dividends declared but not paid:			
Common stock	$ —	$ 100	$ 100
Preferred and preference stock	13	13	13

Note 13. Preferred and Preference Stock

SCE's authorized shares are: $100 cumulative preferred – 12 million shares $25 cumulative preferred – 24 million shares and preference with no par value – 50 million shares. SCE's outstanding shares are not subject to mandatory redemption. There are no dividends in arrears for the preferred stock or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock was issued or redeemed in the years ended December 31, 2010 and 2009. There is no sinking fund requirement for redemptions or repurchases of preferred stock.

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

Preferred stock and preference stock is:

(in millions, except per-share amounts)	Shares Outstanding	Redemption Price	December 31, 2010	2009
Cumulative preferred stock				
$25 par value:				
4.08% Series	650,000	$ 25.50	$ 16	$ 16
4.24% Series	1,200,000	25.80	30	30
4.32% Series	1,653,429	28.75	41	41
4.78% Series	1,296,769	25.80	33	33
Preference stock				
No par value:				
5.5% Series A (variable)	4,000,000	100.00	400	400
6.125% Series B	2,000,000	100.00	200	200
6.00% Series C	2,000,000	100.00	200	200
			$ 920	$ 920

The Series A and B preference stock were issued in 2005 and the Series C preference stock was issued in 2006. SCE may, at its option, redeem the Series A, B, or C preference stock in whole or in part. No preference stock was redeemed in the last three years.

At December 31, 2010 accrued dividends related to SCE's preferred and preference stock were $13 million.

Note 14. Regulatory Assets and Liabilities

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

Balancing account under-collections and over-collections accrue interest based on a three-month commercial paper rate published by the Federal Reserve.

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

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

(in millions)	December 31, 2010	2009
Current:		
Regulatory balancing accounts	$ 213	$ 94
Energy derivatives	162	25
Other	3	1
	378	120
Long-term:		
Deferred income taxes – net	1,855	1,561
Pensions and other postretirement benefits	1,097	1,014
Unamortized generation investment – net	355	413
Unamortized loss on reacquired debt	268	287
Energy derivatives	177	357
Nuclear-related ARO investment – net	154	258
Unamortized distribution investment – net	105	—
Regulatory balancing accounts	56	43
Other	280	206
	4,347	4,139
Total Regulatory Assets	$ 4,725	$ 4,259

SCE's regulatory assets related to energy derivatives are primarily an offset to unrealized losses on derivatives. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to income taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory assets related to pensions and other post-retirement plans represents the recoverable portion of the additional amounts recorded in accordance with authoritative guidance on accounting for pensions and post-retirement plans (see "Pension Plans and Postretirement Benefits Other than Pensions" discussion in Note 8). This amount will be recovered through rates charged to customers. SCE's unamortized generation investment includes nuclear assets related to San Onofre which are expected to be recovered by 2022, nuclear assets related to Palo Verde which are expected to be recovered by 2027 and SCE's unamortized coal plant investment which is being recovered through June 2016. Unamortized distribution investment includes legacy meters retired as part of the EdisonSmartConnect™ program which are expected to be recovered by 2025. Although SCE's unamortized generation and distribution investments are classified as regulatory assets on the consolidated balance sheets, they continue to be a component of rate base and earned an 8.75% return in both 2010 and 2009. SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 28 years.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

(in millions)	December 31, 2010	December 31, 2009
Current:		
Regulatory balancing accounts	$ 733	$ 363
Other	5	4
	738	367
Long-term:		
Costs of removal	2,623	2,515
ARO	1,099	171
Regulatory balancing accounts	802	642
	4,524	3,328
Total Regulatory Liabilities	$ 5,262	$ 3,695

SCE's regulatory liability related to the ARO represents timing differences between the ARO and the assets of the nuclear decommissioning trust. The balance varies due to changes in the ARO as well as nuclear decommissioning trust investment activities. SCE's regulatory liabilities related to costs of removal represent operating revenue collected for asset removal costs that SCE expects to incur in the future. These balances will be returned to ratepayers in a future ratemaking proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the ratemaking process, or be applied as otherwise directed by the CPUC.

Note 15. Other Investments

Nuclear Decommissioning Trusts

Future nuclear decommissioning costs of removal of nuclear assets are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $23 million per year included in SCE customer rates. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

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

		Amortized Cost		Fair Value	
	Longest Maturity	December 31,		December 31,	
(in millions)	Dates	2010	2009	2010	2009
Stocks	–	$ 895	$ 822	$ 2,029	$ 1,772
Municipal bonds	2049	706	545	790	634
Corporate bonds	2044	288	309	346	393
U.S. government and agency securities	2040	270	287	288	308
Short-term investments and receivables/payables	One-year	26	33	27	33
Total		$ 2,185	$ 1,996	$ 3,480	$ 3,140

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Proceeds from sales of securities (which are reinvested) were $1.4 billion, $2.2 billion and $3.1 billion for the years ended December 31, 2010, 2009 and 2008, respectively. Unrealized holding gains, net of losses, were $1.3 billion and $1.1 billion at December 31, 2010 and 2009, respectively. Approximately 92% of the cumulative trust fund contributions were tax-deductible.

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

(in millions)	2010	2009	2008
Balance at beginning of period	$ 3,140	$ 2,524	$ 3,378
Realized gains (losses) – net	121	95	(65)
Unrealized gains (losses) – net	148	526	(545)
Other-than-temporary impairments	(27)	(111)	(317)
Interest, dividends, contributions and other	98	106	73
Balance at end of period	$ 3,480	$ 3,140	$ 2,524

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

Note 16. Other Income and Expenses

Other income and expenses are as follows:

	Years ended December 31,		
(in millions)	2010	2009	2008
Other income:			
Equity AFUDC	$ 100	$ 116	$ 54
Increase in cash surrender value of life insurance policies	25	23	24
Energy settlement	5	9	3
Other	11	12	20
Total other income	$ 141	$ 160	$ 101
Other expenses:			
Penalties	$ —	$ —	$ 59
Civic, political and related activities and donations	28	28	34
Marketing services	7	11	11
Other	16	10	19
Total other expenses	$ 51	$ 49	$ 123

During 2009, the CPUC and FERC authorized the transfer of the Mountainview power plant to utility rate base which resulted in a one time, non-cash accounting benefit of approximately $46 million. This non-cash accounting benefit primarily resulted from the establishment of regulatory assets to recognize $50 million in differences in the accounting treatment for non-regulated and rate-regulated entities mainly related to equity AFUDC. There was no economic impact to customers from this change as compared to the FERC-approved power-purchase agreement. The transfer resulted in a $603 million increase in SCE's utility property, plant and equipment.

The 2008 penalty primarily resulted from a CPUC decision in September 2008 related to SCE incentives claimed under a CPUC-approved PBR mechanism.

Note 17. Quarterly Financial Data (Unaudited)

(in millions)	Total	Fourth	Third	Second	First
			2010		
Operating revenue	$ 9,983	$ 2,479	$ 3,098	$ 2,247	$ 2,159
Operating income	1,864	383	696	404	380
Net income	1,092	194	407	314	177
Net income available for common stock	1,040	181	394	301	164
Common dividends declared	200	100	100	—	—
			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	—

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. SCE recorded after-tax earnings benefits of $53 million and $42 million in the second and third quarters of 2010, respectively, and recorded after-tax earnings benefits of $300 million and $6 million in the second and fourth quarters of 2009, respectively, 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 President 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 President and Chief Financial Officer concluded that, as of the end of the period, SCE's disclosure and procedures were effective.

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 President 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, 2010.

Change in Internal Control Over Financial Reporting

There were no changes in SCE's internal control over financial reporting 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.

Jointly Owned Utility Plant

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

ITEM 9B. OTHER INFORMATION

On February 24, 2011, the SCE Board of Directors elected Russell C. Swartz as Senior Vice President and General Counsel. Stephen E. Pickett, who had served as SCE's General Counsel from January 2002 to February 2011, will continue as Executive Vice President, External Relations at SCE.

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 28, 2011, 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. 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 corporate governance 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 106 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.

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

(in millions)	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
For the Year ended December 31, 2010					
Uncollectible accounts					
Customers	$ 33.9	$ 27.0	$ —	$ 24.8	$ 36.1
All others	19.0	14.8	22.8	7.2	49.4
Total	$ 52.9	$ 41.8	$ 22.8	$ 32.0[a]	$ 85.5
For the Year ended December 31, 2009					
Uncollectible accounts					
Customers	$ 28.4	$ 28.7	$ —	$ 23.2	$ 33.9
All others	10.3	20.6	—	11.9	19.0
Total	$ 38.7	$ 49.3	$ —	$ 35.1[a]	$ 52.9
For the Year ended December 31, 2008					
Uncollectible accounts					
Customers	$ 20.6	$ 28.7	$ —	$ 20.9	$ 28.4
All others	13.9	8.2	—	11.8	10.3
Total	$ 34.5	$ 36.9	$ —	$ 32.7[a]	$ 38.7

[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/ Chris C. Dominski

Chris C. Dominski
Vice President and Controller
(Duly Authorized Officer and Principal Accounting Officer)

Date: February 28, 2011

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: Ronald L. Litzinger*	President
Principal Financial Officer: Linda G. Sullivan*	Senior Vice President and Chief Financial Officer
Principal Accounting Officer: Chris C. Dominski	Vice President and Controller
Board of Directors:	
Jagjeet S. Bindra*	Director
Vanessa C.L. Chang*	Director
France A. Córdova*	Director
Theodore F. Craver, Jr.*	Director
Charles B. Curtis*	Director
Bradford M. Freeman*	Director
Ronald L. Litzinger*	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/ Chris C. Dominski

Chris C. Dominski
Vice President and Controller
(Attorney-in-fact)

Date: February 28, 2011

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 January 1, 2011 (File No. 1-9936, filed as Exhibit 3.2 to Southern California Edison Company's Form 8-K for dated December 10, 2010)*
4.1	Edison International Senior Indenture, dated September 10, 2010 (File No. 1-9936, filed as Exhibit 4.1 to Edison International's Form 10-Q for the quarter ended September 30, 2010)*
4.2	Southern California Edison Company First Mortgage Bond Trust Indenture, dated as of October 1, 1923, Restated with all Amendments
4.3	Southern California Edison Company Indenture, dated as of January 15, 1993 (File No. 1-2313, Form 8-K dated January 28, 1993)*
10.1**	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)*
10.2**	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)*
10.3**	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)*
10.4**	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)*
10.4.1**	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)*
10.4.2**	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)*
10.5**	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)*
10.6**	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)*
10.7**	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)*
10.7.1**	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)*
10.8**	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
10.9**	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)*
10.10**	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)*
10.11**	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)*
10.12**	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)*
10.13**	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)*
10.14**	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)*
10.15**	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)*
10.15.1**	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)*
10.15.2**	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)*
10.16**	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)*
10.17**	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)*
10.17.1**	Edison International 2008 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, 2008)*
10.17.2**	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)*
10.17.3**	Edison International 2010 Long-Term Incentives Terms and Conditions (File No. 1-9936 filed as Exhibit 10.2 to Edison International Form 10-Q for the quarter ended March 31, 2010)*
10.18**	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)*
10.18.1**	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)*
10.18.2**	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)*

Exhibit Number	Description
10.18.3**	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)*
10.18.4**	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)*
10.18.5**	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)*
10.19**	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)*
10.19.1**	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)*
10.19.2*	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)*
10.20**	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)*
10.20.1**	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)*
10.20.2**	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)*
10.20.3**	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)*
10.21**	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)*
10.22**	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)*
10.22.1**	Amendment to 2008 Executive Severance Plan, effective December 8, 2010 (File No. 1-9936, filed as Exhibit 10.21.1 to Edison International's Form 10-K for the year ended December 31, 2010)*
10.23**	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)*
10.24**	Edison International Director Matching Gifts Program, as adopted June 24, 2010 (File No. 1-9936, filed as Exhibit 10.1 to Edison International's Form 10-Q for the quarter ended June 30, 2010)*

Exhibit Number	Description
10.25**	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)*
10.26	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)*
10.26.1	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)*
10.26.2	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)*
10.26.3	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)*
10.26.4	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)*
10.27**	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)*
10.28	Edison International 2010 Executive Annual Incentive Program (File No. 1-9936, filed as Exhibit 10.1 to the Edison International's Form 10-Q for the quarter ended March 31, 2010)*
10.29**	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)*
10.30**	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)*
10.30.1**	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)*
10.31	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)*
10.31.1	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)*

Exhibit Number	Description
10.31.2	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)*
10.32	Credit Agreement dated as of March 5, 2010 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., SunTrust Bank, UBS Loan Finance LLC, US Bank, National Association, BNP Paribas, Royal Bank of Canada, and The Bank of Nova Scotia as Co-Documentation Agents, and the lenders thereto. (File No. 1-2313, filed as Exhibit 10 to Southern California Edison Company form 8-K dated March 5, 2010)*
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
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, 2010, filed on February 28, 2011, 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

Ronald L. Litzinger
President
Southern California Edison
A director since 2010

Jagjeet Bindra[1,3]
Retired President
Chevron Global Manufacturing
(an integrated energy company)
Dallas, Texas
A director since 2010

Vanessa C.L. Chang[1,3]
Principal
EL & EL Investments
(private real estate investment company)
Los Angeles, California
A director since 2007

France A. Córdova[3,4]
President
Purdue University
West Lafayette, Indiana
A director since 2004

Theodore F. Craver
Chairman of the Board,
President and
Chief Executive Officer
Edison International
A director since 2007

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President Emeritus
Nuclear Threat Initiative
(private foundation dealing with
national security issues)
Washington, DC
A director since 2006

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Freeman Spogli & Co.
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Los Angeles, California
A director since 2002

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Managing Partner
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

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Senior Partner
Munger, Tolles & Olson (law firm)
Los Angeles, California
A director since 1995

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California State University, Los Angeles
Los Angeles, California
A director since 1988

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Retired President and
Chief Executive Officer
The David and Lucile Packard Foundation
(private family foundation)
San Antonio, Texas
A director since 2002

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Retired Chairman of the Board and
Chief Executive Officer
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

Brett White[2,4]
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 Finance Committee
4 Nominating/Corporate Governance Committee

Management Team

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Executive Vice President,
External Relations

Lynda L. Ziegler
Executive Vice President,
Power Delivery Services

Peter T. Dietrich
Senior Vice President,
Generation and
Chief Nuclear Officer

Bruce C. Foster
Senior Vice President,
Regulatory Affairs

Stuart R. Hemphill
Senior Vice President,
Power Supply

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

James A. Kelly
Senior Vice President,
Transmission and Distribution

Linda G. Sullivan
Senior Vice President and
Chief Financial Officer

Russell C. Swartz
Senior Vice President and
General Counsel

Gaddi H. Vasquez
Senior Vice President,
Public Affairs

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

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Generation and
Station Manager,
San Onofre Nuclear Generating Station

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Vice President,
Energy Supply and Management

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Vice President and
Associate General Counsel

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

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Vice President,
Associate General Counsel,
Chief Governance Officer and
Corporate Secretary

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Vice President,
Engineering and Technical Services

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Vice President,
Human Resources

Stacy R. Mines
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Chief Ethics and Compliance Officer

Kevin M. Payne
Vice President,
Information Technology and
Business Integration

Walter Rhodes
Vice President,
Supply Management

Megan Scott-Kakures
Vice President and General Auditor

Leslie E. Starck
Vice President,
Local Public Affairs

Marc L. Ulrich
Vice President,
Renewable and Alternative Power

SHAREHOLDER INFORMATION

Annual Meeting

The annual meeting of shareholders will be held on Thursday, April 28, 2011, 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 NYSE Amex Equities stock exchange. Previous day's closing prices, when stock was traded, are listed in the daily newspapers under NYSE Amex. 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[SM]
www.wellsfargo.com/shareownerservices

Investor Relations

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Online account information

www.shareowneronline.com

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