SOUTHERN CALIFORNIA
EDISON®
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2008 Annual Report

Southern California Edison Company

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities serving a population of more than 13 million via 4.8 million customer accounts in a 50,000-square-mile service area within central, coastal and Southern California.

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Glossary

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

AB	Assembly Bill
ACC	Arizona Corporation Commission
AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	Clean Air Resources Board
CDWR	California Department of Water Resources
CEC	California Energy Commission
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
District Court	U.S. District Court for the District of Columbia
DOE	United States Department of Energy
DOJ	Department of Justice
DPV2	Devers-Palo Verde II
DRA	Division of Ratepayer Advocates
DWP	Los Angeles Department of Water & Power
EITF	Emerging Issues Task Force
EITF No. 01-8	EITF Issue No. 01-8, Determining Whether an Arrangement Contains a Lease
EME	Edison Mission Energy
ERRA	energy resource recovery account
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGIC	Financial Guarantee Insurance Company
FIN 39-1	Financial Accounting Standards Interpretation No. 39-1, Amendment of FASB Interpretation No. 39
FIN 46(R)	Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities
FIN 46(R)-6	Financial Accounting Standards Board Interpretation No. 46(R)-6, Determining Variability to be Considered in Applying FIN 46(R)

FIN 47	Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations
FIN 48	Financial Accounting Standards Interpretation No. 48, Accounting for Uncertainty in Income Taxes — an interpretation of FAS 109
FSP	FASB Staff Position
FTRs	Firm transmission rights
GAAP	generally accepted accounting principles
GHG	greenhouse gas
Global Settlement	A settlement that has been negotiated between Edison International and the IRS, which, if consummated, would resolve outstanding tax disputes for all Edison International subsidiaries, including SCE, for open tax years 1986 through 2002, including affirmative claims for unrecognized tax benefits. There can be no assurance about the timing of such settlement or that a final settlement will be ultimately consummated.
GRC	General Rate Case
Investor-Owned Utilities	SCE, SDG&E and PG&E
IRS	Internal Revenue Service
ISO	California Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mohave	Mohave Generating Station
MRTU	Market Redesign Technical Upgrade
MW	megawatts
MWh	megawatt-hours
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NOx	nitrogen oxide
NRC	Nuclear Regulatory Commission
Palo Verde	Palo Verde Nuclear Generating Station
PBOP(s)	postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
POD	Presiding Officer's Decision
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RICO	Racketeer Influenced and Corrupt Organization
ROE	return on equity

Glossary (Continued)

S&P	Standard & Poor's
SAB	Staff Accounting Bulletin
San Onofre	San Onofre Nuclear Generating Station
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 71	Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation
SFAS No. 115	Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities
SFAS No. 123(R)	Statement of Financial Accounting Standards No. 123(R), Share-Based Payment (revised 2004)
SFAS No. 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and hedging Activities
SFAS No. 143	Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations
SFAS No. 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements
SFAS No. 158	Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Post-Retirement Plans
SFAS No. 159	Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities
SFAS No. 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements
SFAS No. 161	Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133
SO_2	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
The Tribes	Navajo Nation and Hopi Tribe
TURN	The Utility Reform Network
VIE(s)	variable interest entity(ies)

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INTRODUCTION

This MD&A contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements reflect SCE's current expectations and projections about future events based on SCE's knowledge of present facts and circumstances and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by SCE that is incorporated in this report, or that refers to or incorporates this report, may also contain forward-looking statements. In this report and elsewhere, the words "expects," "believes," "anticipates," "estimates," "projects," "intends," "plans," "probable," "may," "will," "could," "would," "should," and variations of such words and similar expressions, or discussions of strategy or of plans, are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ, or that otherwise could impact SCE, include, but are not limited to:

- the cost of capital and the ability to borrow funds and access to capital markets on favorable terms, particularly in light of current credit conditions in the capital markets;
- the effect of current economic conditions on the 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;
- the ability to procure sufficient resources to meet expected customer needs in the event of significant counterparty defaults under power-purchase agreements;
- changes in the fair value of investments and other assets;
- the ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- market risks affecting SCE's energy procurement activities;
- changes in interest rates, rates of inflation 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;
- environmental laws and regulations, both at the state and federal levels, that could require additional expenditures or otherwise affect the cost and manner of doing business;
- risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage, equipment failure, availability, heat rate, output, availability and cost of spare parts, and cost of repairs and retrofits;
- the cost and availability of labor, equipment and materials;
- the ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities and wildfire-related liability, and to recover the costs of such insurance;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- the outcome of disputes with the IRS and other tax authorities regarding tax positions taken by SCE;
- the cost and availability of coal, natural gas, fuel oil, nuclear fuel, and associated transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;
- the cost and availability of emission credits or allowances for emission credits;

- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the ability to provide sufficient collateral in support of hedging activities and purchased power and fuel;
- the risk of counterparty default in hedging transactions or power-purchase and fuel contracts;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- the risks inherent in the development of generation projects as well as transmission and distribution infrastructure replacement and expansion including those related to siting, financing, construction, permitting, and governmental approvals.

Additional information about risks and uncertainties, including more detail about the factors described above, are discussed throughout this MD&A and in the "Risk Factors" section included in Part I, Item 1A of SCE's Annual Report on Form 10-K. Readers are urged to read this entire report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect 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 Securities & Exchange Commission.

This MD&A is presented in nine major sections: (1) Management Overview; (2) Regulatory Matters; (3) Other Developments; (4) Liquidity (5) Market Risk Exposures; (6) Results of Operations and Historical Cash Flow Analysis; (7) Critical Accounting Estimates and Policies; (8) New Accounting Pronouncements; and (9) Commitments and Indemnities.

MANAGEMENT OVERVIEW

Areas of Business Focus

Financial Markets and Economic Conditions

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

SCE is a capital intensive businesses and depends on access to the financial markets to fund capital expenditures, meet contractual obligations, support energy procurement and margin and collateral requirements. SCE has significant planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. SCE's capital plan will require liquidity and access to capital markets at reasonable rates in the future. See "Liquidity" and "Commitments and Indemnities" for further discussion.

Due to the instability of the financial markets and their participants, and to provide protection against a liquidity crisis, SCE borrowed under its credit facility a total of $1.29 billion during the second half of 2008, although there was no immediate need for such funds. As of December 31, 2008, SCE had $2 billion of available liquidity made up of $1.61 billion of cash and short-term investments, as well as $385 billion remaining available under credit facilities. In addition, in October 2008, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014. The bond proceeds further augmented SCE's cash position. SCE does not have any material long-term debt obligations that mature until 2014 (see "Liquidity"). While the capital markets are expected to recover over time, it is uncertain how long it will be before a recovery occurs. Long-term disruption in the capital markets could adversely affect SCE's business plans and potentially impact SCE's financial position.

SCE relies on power-purchase contracts to meet a significant portion of its resource requirements. The financial crisis may adversely affect the ability of counterparties to access the capital markets, as needed, to perform under contracts upon which SCE will rely to meet new generation and renewables portfolio standard requirements. Additionally, if counterparties fail to deliver under power-purchase contracts, SCE would be exposed to potentially volatile spot markets for buying replacement power, but would expect to recover any additional costs through regulatory mechanisms. The volatile market conditions have also affected the value of trusts established at SCE to fund future long-term pension, other postretirement benefits, and nuclear decommissioning obligations. The market decline has decreased the funded status of these plans and unless the market recovers, will result in increased future expense and higher funding levels. SCE currently recovers and expects to continue to recover its pension, other postretirement benefits, and decommissioning costs, through customer rates and therefore funded cost increases are not expected to impact earnings, but may impact the timing of cash flows (see "Liquidity" and "Other Developments" for further discussion).

SCE operates in a large and economically diverse service territory that covers central, coastal and southern California. Economic conditions are also affecting SCE's customers and the demand for electricity. California's economy is experiencing rising unemployment and increased foreclosures and bankruptcies. During 2008, SCE experienced a 10% increase in customer disconnects and a slight increase in the dollar amounts written off for uncollectible customer accounts, compared to 2007. In a February 2009 Integrated Energy Policy Report filed with the CEC for purposes of electricity resource planning, SCE forecast a 4.3% decrease in kWh sales in 2009, compared to 2008. About one-half of this decline is the result of a transition from a warmer than normal summer in 2008 to a more typical summer in 2009. The CPUC-authorized decoupling revenue mechanisms allow for differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers and therefore insulate SCE's short-term earnings from the economic contractions occurring in the U.S. and California. However, a prolonged period of lower sales could decrease future earnings as a result of lower levels of investment required to meet customer needs. SCE's rates are expected to increase in this period of economic downturn, which may further impact customers. See "Regulatory Matters — Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates," "— 2009 General Rate Case Proceeding," and "— Energy Resource Recovery Account Proceedings" for further discussion. Under SCE's tiered rate structure, rate increases are concentrated and not borne by all customers.

The American Recovery and Reinvestment Act of 2009

President Obama signed the American Recovery and Reinvestment Act of 2009 (the "Act") into law on February 17, 2009. The law contains direct spending measures and tax cuts totaling approximately $787 billion. The Act provides production tax credits for a ten-year period for new wind projects placed in service prior to December 31, 2012 and provides that, in lieu of the production tax credit, renewable developers may make an election to claim either a 30% investment tax credit or a grant for a 30% reimbursement of expenses associated with specified energy property. The Act also contains a one year extension of the 50% bonus depreciation, with an extra year available for long lived property, which includes like transmission and distribution assets. Energy spending initiatives in the Act include: $6 billion in loan guarantees for renewable energy and transmission, $4.5 billion to be spent on smart grid investments, $5 billion for weatherization and $3.1 billion in state energy program funds to promote energy efficiency. The Act provides significant support to plug-in hybrid electric vehicle commercialization, including $2 billion in grants for advanced batteries and new or enhanced tax credits for vehicle manufacturing, infrastructure and vehicle purchases, as well as $400 million for port and truck-stop electrification.

Commodity Prices

SCE purchases approximately 44% of its resource needs. SCE expects that these purchases could increase significantly as the CDWR energy contracts are phased out by 2011 and SCE enters into new or novated contracts to replace or assume responsibility for the energy supplied from the CDWR contracts. In addition to

SCE's Mountainview and peaker plants, approximately 46% of SCE's power purchase requirements are subject to natural gas price volatility. Natural gas prices increased significantly during the first half of 2008 and decreased significantly in the second half of the year. Because SCE recovers its procurement costs through the ERRA balancing account mechanism, these market fluctuations do not impact earnings, but can build rapidly and can greatly impact cash flow and customer rates. See "Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates" and "— Energy Resource Recovery Account Proceedings."

Growth Activities and Capital Commitments

Although SCE is experiencing significant growth in actual and planned capital expenditures to improve reliability and expand capability of its distribution and transmission infrastructure, to construct and replace generation assets, and to deploy advanced metering infrastructure, the level of future growth is dependent on a final outcome of its 2009 GRC and other pending CPUC and FERC proceedings. SCE's 2009 through 2013 capital investment plan includes total capital spending in the range of $17.1 billion to $21 billion. See "SCE: Regulatory Matters — Current Regulatory Developments — 2009 General Rate Case Proceeding," and "SCE: Liquidity — Capital Expenditures" for further discussions. These plans would involve the most significant infrastructure build-out of its kind that SCE has undertaken in years. The completion of the projects, the timing of expenditures, and the associated recovery may be affected by permitting requirements and delays, construction delays, availability of labor, equipment and materials, financing, legal and regulatory developments, weather, economic conditions and other unforeseen conditions. In addition, SCE has pending FERC proceedings related to its 2009 FERC Rate Case and CWIP incentive filings that may further impact SCE's capital investment plan.

Federal and State Income Taxes

Edison International has negotiated the material terms of a Global Settlement with the IRS which, if consummated, would resolve outstanding tax disputes for all Edison International subsidiaries, including SCE, for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. See "Southern California Edison Company Notes to Consolidated Financial Statements — Note 4. Income Taxes." Consummation of the Global Settlement is subject to review by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee"). The IRS submitted the pertinent terms of the Global Settlement to the Joint Committee during the fourth quarter of 2008, and its response is currently pending. Edison International cannot predict when such review will be completed or the outcome of such review. See "Other Developments — Federal and State Income Taxes" for further information.

Environmental Developments

Climate Change Regulation

The content of potential climate change regulation in the future remains uncertain. While debate continues at the national level over domestic climate policy and the appropriate scope and terms of any federal legislation, many states are developing state-specific measures or participating in regional legislative initiatives to reduce GHG emissions. State and regional regulations may vary and may be more stringent and costly than federal legislative proposals currently being debated in U.S. Congress. Key uncertainties include whether a cap-and-trade program will be implemented similar to the US EPA acid rain program, and, if implemented, whether emission allowances would be provided to affected parties without cost for a period of time. In the absence of legislation, it is also possible that CO_2 will be regulated by the US EPA pursuant to authority granted under the CAA in its current form. Furthermore, the rate of decrease in GHG emissions and the cost to purchase allowances would be significant factors in determining whether environmental controls for other emissions would be economic to install. Programs to reduce GHG emissions could significantly increase the cost of generating electricity from fossil fuels as well as the cost of purchased power. In the case of utilities, like SCE, these costs are generally borne by customers, whereas the increased costs for competitive generation must be recovered through market prices for electricity. The potential impact on SCE will depend upon how the factors discussed above and many other considerations are resolved.

In the absence of any federally imposed climate change regulation, California's Global Warming Solutions Act of 2006 (also known as AB32) set an overall goal of reducing GHG emissions to 1990 levels by 2020. The program, which is being established by the CARB, to implement AB32 includes, among other measures, an increase to the existing CPUC-imposed renewables portfolio standard of 20% by 2010 to a 33% renewables procurement standard by 2020. Compliance with the 33% renewables portfolio standard would require, among other items, substantial additional power purchase contracts and capital expenditures to expand SCE's distribution and transmission infrastructure, all at a significant cost.

Water Quality Regulations

Federal water quality regulations regulate the discharge of pollutants into federal waters, the heat of effluent discharges and the location, design and construction of cooling water intake structures at generation facilities. State regulations also cover certain discharges that are not regulated at the federal level.

In the absence of federal regulations, which are currently the subject of litigation and rulemaking, California is developing a policy on ocean-based once-through cooling structures, although the timing of such policy becoming effective is uncertain. The policy is expected to have a substantial effect on grid reliability in the CAISO service area, including on operations at San Onofre and on SCE's ability to procure generating capacity from fossil-fueled plants using ocean water once-through cooling systems. As of December 31, 2008, approximately 18,500 MW in the CAISO service area would be subject to this once-through cooling policy.

See "Other Developments — Environmental Matters" for a further discussion of these and other environmental matters.

2008 Earnings Performance

SCE's earnings from continuing operations were $683 million in 2008, compared with earnings of $707 million in 2007. The decrease in 2008 was mainly attributable to a $49 million charge associated with the CPUC decision on SCE's performance-based ratemaking mechanism recorded in 2008 and a $31 million tax benefit from the resolution of the income tax treatment of certain environmental remediation costs recorded in 2007, partially offset by higher operating income related to rate base growth, including authorized energy efficiency incentives, and lower net interest expense.

SOUTHERN CALIFORNIA EDISON COMPANY

REGULATORY MATTERS

Overview of Ratemaking Mechanisms

SCE is an investor-owned utility company providing electricity to retail customers in central, coastal and southern California. SCE is regulated by the CPUC and the FERC. SCE bills its retail customers for the sale of electricity at rates authorized by the CPUC. These rates are discussed below under four categories: base rates, cost-recovery rates, energy efficiency incentives and CDWR-related rates. SEC sells unbundled transmission service and wholesale power at rates and under tariffs authorized by the FERC.

Base Rates

Revenue arising from base rates from the CPUC and the FERC are designed to provide SCE a reasonable opportunity to recover its costs and earn an authorized return on SCE's 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.

Base rates related to SCE's generation and distribution functions are authorized by the CPUC through a triennial process called the GRC. In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement for a base year and two subsequent years. After a review process and hearings, the CPUC sets an annual revenue requirement for the base year which is made up of the carrying cost on capital investment (depreciation, return and taxes), plus the authorized level of operation and maintenance expense. The return is established by multiplying an authorized rate of return, determined in the separate cost of capital proceedings (as discussed below), by rate base (the value of assets on which SCE earns a rate of return for investors). In its GRC proceedings, SCE also submits testimony regarding its need for capital spending on a forecast basis which is reviewed and approved, if found reasonable by the CPUC. Adjustments to the revenue requirement for the remaining two years of a typical three-year GRC cycle are requested from the CPUC, based on criteria established in the GRC proceeding which generally include annual allowances for escalation in operation and maintenance costs, forecasted changes in capital-related investments and related costs and the timing and number of expected nuclear refueling outages and their related forecasted costs. See "— Current Regulatory Developments — 2009 General Rate Case Proceeding" for SCE's current annual revenue requirement.

The CPUC-authorized decoupling revenue mechanisms allow for differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers and therefore do not impact SCE's earnings. Differences between authorized and actual operating costs, other than cost-recovery costs (see below), do impact earnings.

Base rate revenue related to SCE's transmission facilities are authorized by the FERC, as needed, in periodic proceedings that are similar to the CPUC's GRC proceeding, except that requested rate changes are generally implemented either 60 days after the application is filed or after a maximum five month suspension. Revenue collected prior to a final FERC decision is recognized as revenue, but is subject to refund. Revenue authorized under FERC jurisdiction that varies from forecast is not subject to balancing account mechanisms, is not recoverable or refundable and can therefore impact operating returns.

SCE's capital structure and related authorized rate of return, is regulated by the CPUC and the FERC. The CPUC jurisdictional cost of capital is applicable to the costs recovered through jurisdictional base rates. The FERC jurisdictional cost of capital is applicable to FERC jurisdictional base rates designed to recover transmission costs. Currently, the CPUC determines SCE's cost of capital in a multi-year proceeding occurring every three years. SCE expects that the current capital structure and authorized rate of return will remain in place until January 2011, absent any potential annual adjustment, as discussed below. SCE's current authorized capital structure is 48% common equity, 43% long-term debt and 9% preferred equity. SCE's current authorized cost of long-term debt is 6.22%, authorized cost of preferred equity is 6.01% and authorized return on common equity is 11.5%. The three-year cost of capital mechanism provides for an automatic readjustment to SCE's capital costs during the years between the cost of capital filings if certain thresholds are reached on an annual basis. SCE's next potential adjustment will occur at the end of September 2009, effective for 2010. As a result, depending on financial market conditions, SCE is subject to the potential earnings impact of actual financing costs being above or below its authorized rates of 6.22% and 6.01% for new long-term debt and preferred equity financings, respectively, during 2009.

Cost-Recovery Rates

Revenue requirements 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 are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 62% of SCE's annual revenue relates to the recovery of these costs. Although the CPUC authorizes balancing account mechanisms to refund or recover any differences between forecasted and actual costs, under- or over-collections in these balancing accounts can build rapidly due to fluctuating prices (particularly for purchased-power) and can greatly impact cash flows. The majority of costs eligible for recovery through cost-recovery rates are subject to CPUC reasonableness reviews, and thus could negatively impact earnings and cash flows if found to be unreasonable and disallowed.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

The CPUC has adopted an Energy Efficiency Risk/Reward Incentive Mechanism covering two three-year periods (2006 – 2008 and 2009 – 2011). The mechanism allows for both financial incentives and economic penalties based on SCE's performance toward meeting CPUC goals for energy efficiency. Under this mechanism, SCE has the opportunity to earn an incentive of 9% of the value of total energy efficiency savings if it achieves between 85% and 100% of its energy efficiency goals for the cumulative three year period or can earn 12% of the value of energy efficiency savings if 100% or greater of its goals are achieved. Economic penalties would be imposed in the event SCE achieves less than 65% of its goals. The mechanism has a deadband between 65% and 85% of energy efficiency goals, where no economic penalty or incentive would be earned. The mechanism allows for two progress payments, subject to a 35% holdback, for estimated progress towards meeting CPUC-authorized 3-year goals and a third payment for final measured performance towards those goals, which includes the payment of any holdback. SCE may retain the first and second progress payments as long as it meets a minimum of 65% of the goals, as measured by the CPUC in the final payment. If SCE falls below the 65% level, the amount of the progress payments and economic penalties would be deducted from future earnings awards. Both incentives and economic penalties for each three-year period are capped at $200 million. There is no assurance that SCE will meet its goals of energy efficiency incentive earnings in any given year. In addition, certain aspects of the energy efficiency incentive mechanism remain subject to CPUC review and possible modification. See "Current Regulatory Developments — Energy Efficiency Shareholder Risk/Reward Incentive Mechanism" for further discussion of current developments related to the 2006 – 2008 program cycle.

CDWR-Related Rates

As a result of the California energy crisis, in 2001 the CDWR entered into contracts to purchase power for sale at cost directly to SCE's retail customers and issued bonds to finance those power purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of the Investor-Owned Utilities. SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. The CDWR-related charges and a portion of direct access exit fees (approximately $2.2 billion was collected in 2008) are remitted directly to the CDWR, are not recognized as operating revenue by SCE and therefore have no impact on SCE's earnings; however, they do impact customer rates. See "— Impact of Regulatory Matters on Customer Rates" for further discussion.

Current Regulatory Developments

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

Impact of Regulatory Matters on Customer Rates

Throughout the year, SCE changes rates to implement various regulatory decisions. SCE's current system average rate is 13.7¢ per-kWh (2.8¢ per-kWh related to CDWR, which is not recognized as revenue by SCE).

SCE expects to implement a rate change March 1, 2009 related to 2009 procurement-related costs and the 2009 FERC rate case offset by decreases in the 2009 CDWR power charge revenue requirement. This rate change is expected to result in a system average rate of 13.4¢ per-kWh (2.3¢ per-kWh related to CDWR, which is not recognized as revenue by SCE). See "— Energy Resource Recovery Account Proceedings — 2008 ERRA Revenue Requirements Forecast" and "— 2009 FERC Rate Case" for further information.

During the 2001 energy crisis, the California Legislature passed a bill, AB 1X, which implemented a tiered rate structure that capped, or fixed, the rates for almost half of SCE's residential customers. As a result, any residential revenue requirement increase is allocated to the remaining residential customers. This causes wide variation in the average rates SCE's residential customers pay. This rate inequity is causing increasingly high bills for a subset of SCE's customers. SCE is currently working with the CPUC, consumer groups, and key California public officials to seek support for a means to mitigate the effects of AB 1X.

In May 2007, the CPUC initiated a rulemaking to determine whether, or subject to what conditions, direct access could be restored in California. The proceeding was initially divided into three phases, with the first phase addressing whether the CPUC had the legal authority to lift the suspension of direct access under AB 1X. In February 2008, the CPUC issued a decision, finding that the CPUC could not lift the direct access suspension as long as the CDWR continues to supply power to retail customers as a party to its existing power contracts. The reopening of Direct Access may have an impact on customer rates, however, SCE is unable to predict the outcome or impact of this process at this time.

In November 2008, the CPUC issued a subsequent decision, finding that there are sufficient potential benefits to ratepayers to establish a process that phases-out the CDWR's remaining involvement in supplying power to Investor-Owned Utility customers. The November 2008 decision sets a target goal of novating/replacing by January 1, 2010 all remaining CDWR energy contracts so that the novated/replacement contracts are held instead by the Investor-Owned Utilities. SCE cannot predict whether or not the expedited phase-out of the CDWR contracts will occur on commercially feasible terms and the outcome of the financial impact on SCE.

2009 General Rate Case Proceeding

In February 2009, the Administrative Law Judge issued a revised proposed decision on SCE's 2009 GRC. In addition, CPUC President Peevey further revised his alternate proposed decision in this proceeding. The Administrative Law Judge's revised proposed decision would authorize a $4.6 billion base revenue requirement for 2009, a 24% increase over the 2006 authorized revenue requirement of $3.7 billion and base revenue requirements of $4.8 billion in 2010 and $4.9 billion in 2011. If adopted as currently drafted, this proposed decision would require SCE to reduce its planned capital expenditures in 2009 and 2010 by $2.0 billion with further reductions to be made in 2011, and reduce its forecast operating and maintenance expenditures by more than $400 million. The impacts of these expenditure reductions may compromise SCE's ability to comply with regulatory requirements, maintain its electric system, and provide reliable service to its customers. CPUC President Peevey's revised alternate proposed decision would authorize a $4.9 billion base revenue requirement for 2009, a 30% increase over the 2006 authorized revenue requirement of $3.7 billion, and a methodology for calculating post-test year revenue requirements that would result in an approximate revenue requirement of $5.1 billion in 2010 and $5.4 billion in 2011. While the revised alternate proposed decision authorizes revenue requirements below the level requested in SCE's GRC Application, if adopted as currently drafted, the proposed decision would provide SCE adequate funding to serve its customers. See "SCE: Liquidity" for further discussion of the impact on capital spending.

Both alternate decisions grant SCE's request for the authority to transfer the assets and liabilities of Mountainview Power Company, LLC to SCE. This transfer would facilitate operations of the power plant and reduce administrative compliance requirements. If approved, SCE would expect to record one-time accounting gains of $49 million and $14 million in the form of regulatory assets to recognize differences in the accounting treatment for non-regulated and rate-regulated entities related to equity AFUDC, and capitalization of acquisition costs, respectively. There would be no economic impact to customers from this change as compared to the existing FERC-approved power-purchase agreement; as these amounts would have been recognized over the life of that agreement and have no impact on cash flows. The transfer of Mountainview Power Company, LLC to SCE is also subject to FERC approval which is dependent on final approval of SCE's 2009 GRC Application.

SCE cannot predict whether the CPUC will ultimately adopt one or the other of these proposed decisions.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

As described above under the heading "— Overview of Ratemaking Mechanisms — Energy Efficiency Shareholder Risk/Reward Incentive Mechanism," the CPUC has adopted an Energy Efficiency Risk/Reward Incentive Mechanism. Under the mechanism, if SCE achieves all of its energy efficiency goals, and delivers customer benefits of approximately $1.2 billion, the three-year earnings opportunity for the 2006 – 2008 period would be approximately $146 million pre-tax. On December 18, 2008, the CPUC approved SCE's first progress payment for 2006 – 2007 energy efficiency performances using SCE's quarterly savings report rather than the CPUC verification report which was delayed. However, the CPUC increased the holdback percentage (for this progress payment only) from the originally authorized 35%, to 65%, resulting in a first progress payment of $25 million which is expected to be collected through rates in 2009. The DRA and TURN filed a request for rehearing of the December decision approving the first progress payment. SCE does not believe the request for rehearing will affect the first progress payment award but cannot predict the outcome of this proceeding.

Pursuant to the adopted mechanism, future progress payments are expected to be based on CPUC verification reports. If the CPUC's verification report is again delayed in 2009, the CPUC may approve the second progress payment based upon SCE's quarterly savings report, subject to another review of the progress payment holdback percentage. Currently, SCE intends to file its request for its second progress payment using SCE's final quarterly savings report on March 2, 2009 for the second progress payment. SCE currently projects (using a 65% holdback percentage), based on preliminary results and on the current energy efficiency mechanism guidelines, that it will record a second progress payment in the range of $14 million to $26 million upon CPUC approval, which is expected in the fourth quarter of 2009 for the 2006 – 2008 program cycle. SCE expects to collect this progress payment in rates in 2010. Based on the current mechanism, SCE estimates that it will meet 100% of its energy efficiency goals for the 2006 – 2008 period.

On January 29, 2009, the CPUC issued a new rulemaking intended to address issues with the current mechanism, including delays in the verification process, utility concerns about methodologies used by the CPUC Energy Division in calculating interim incentive payments, and intervenors' concerns about the fairness of the incentive structure. In this rulemaking the CPUC intends to adopt a new framework for the review of the remainder of 2006 – 2008 energy efficiency activities in a timeframe consistent with interim payments for 2008 no later than December 2009, and any final payments for 2006 – 2008 no later than December 2010. There is no assurance of earnings in any given year or that the mechanism will not be changed as a result of the rulemaking issued by the CPUC in January 2009.

2009 FERC Rate Case

In an order issued in September 2008, the FERC accepted and made effective on March 1, 2009, subject to refund and settlement procedures, SCE's proposed revisions to its tariff, filed in the 2009 transmission rate case. The revisions reflected changes to SCE's transmission revenue requirement and transmission rates, as discussed below.

SCE requested a $129 million increase in its retail transmission revenue requirements (or a 39% increase over the current retail transmission revenue requirement) due to an increase in transmission capital-related costs and increases in transmission operating and maintenance expenses that SCE expects to incur in 2009 to maintain grid reliability. The transmission revenue requirement request is based on a return on equity of 12.7%, which is composed of a 12.0% base ROE and 0.7% in transmission incentives previously approved by the FERC (see "— FERC Transmission Incentives" below for further information). SCE is unable to predict the revenue requirement that the FERC will ultimately authorize.

FERC Transmission Incentives

The Energy Policy Act of 2005 established incentive-based rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Pursuant to this act, in November 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects. These include 125 basis point ROE adders on SCE's proposed base ROE for SCE's DPV2 and Tehachapi transmission projects and a 75 basis point ROE adder for SCE's Rancho Vista Substation Project ("Rancho Vista").

In June 2007, the ACC denied the approval of the DPV2 project which resulted in an estimated two year delay of the project. SCE continues its efforts to obtain the regulatory approvals necessary to construct the DPV2 project and continues to evaluate its options, which include but are not limited to, filing a new application with the ACC and building the project in various phases.

The order also grants a 50 basis point ROE adder on SCE's cost of capital for its entire transmission rate base in SCE's next FERC transmission rate case for SCE's participation in the CAISO. In addition, the order on incentives permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction, also known as CWIP, of all three projects and 100% recovery of prudently-incurred abandoned plant costs for two of the projects, if either are cancelled due to factors beyond SCE's control.

In August 2008, the CPUC filed an appeal of the FERC incentives order at the DC Circuit Court of Appeals. The court issued a ruling on November 6, 2008, accepting the CPUC's request that the court refrain from ruling on the CPUC's appeal until a final FERC order is issued in the 2008 CWIP case (see "— FERC Construction Work in Progress Mechanism" below for further information).

FERC Construction Work in Progress Mechanism

FERC CWIP 2008

In February 2008, the FERC approved SCE's revision to its tariff to collect 100% of CWIP in rate base for its Tehachapi, DPV2, and Rancho Vista, as authorized by FERC in its transmission incentives order discussed above. which resulted in an authorized base transmission revenue requirement of $45 million, subject to refund. In March 2008, the CPUC filed a petition for rehearing with the FERC on the FERC's acceptance of SCE's proposed ROE for CWIP and in another 2008 protest to an SCE compliance filing, requested an evidentiary hearing to be set to further review SCE's costs. SCE cannot predict the outcome of the matters in this proceeding.

FERC CWIP 2009

SCE filed its 2009 CWIP rate adjustment in October 2008 proposing a reduction to its CWIP revenue requirement from $45 million to $39 million to be effective on January 1, 2009. Several parties, including the CPUC, filed protests to the October filing in November 2008, primarily contesting SCE's proposed base ROE of 12.0%. The FERC issued an order in December 2008, allowing the proposed 2009 CWIP rates to go into effect on January 1, 2009, subject to refund, and directing that the 2009 CWIP ROE be made subject to the outcome of the pending 2008 FERC CWIP proceeding. The FERC also consolidated all issues other than ROE with SCE's 2009 FERC rate case proceeding (see "2009 FERC Rate Case" above for further information).

Energy Resource Recovery Account Proceedings

The ERRA is the balancing account mechanism that tracks and recovers SCE's fuel and procurement-related costs. SCE files annual forecasts of these costs that it expects to incur during the following year and sets rates using forecasts. At December 31, 2008, the ERRA was under-collected by $406 million, which was 7.6% of SCE's prior year's generation revenue. The CPUC has established a "trigger" mechanism that allows for a rate adjustment if the ERRA balancing account overcollection or undercollection exceeds 5% of SCE's prior year's generation revenue. Due to the recent decrease in natural gas prices, SCE estimates that the ERRA balancing account under collection will be below the trigger threshold by June 2009. Therefore, SCE does not expect to file a trigger application.

2009 ERRA Revenue Requirements Forecast

On January 29, 2009, the CPUC approved SCE's proposal that an increase of $331 million over SCE's adopted 2008 ERRA revenue requirement be reflected in rate levels (which results in a 2009 ERRA revenue requirement of $4.0 billion). The adopted 2009 ERRA revenue requirement change will be implemented in rates on March 1, 2009. The CPUC further agreed to let SCE net a projected $110 million decrease in its 2009 procurement costs against the remaining under-collected ERRA balance in the future and rely on timely trigger applications for additional recovery needs.

Resource Adequacy Requirements

Under the CPUC's resource adequacy framework, all load-serving entities in California have an obligation to procure sufficient resources to meet their expected customers' needs on a system-wide basis with a 15 – 17% reserve level. In addition, on June 6, 2006, the CPUC adopted local resource adequacy requirements.

SCE is required to demonstrate every month that it has met 100% of its system resource adequacy requirement one month in advance of expected need (known as the month-ahead system resource adequacy showing). SCE is also required to make its year-ahead system resource adequacy showing (90% threshold) in the fall of the calendar year prior to the compliance year. The system resource adequacy requirements provide for penalties of 300% of the cost of new monthly capacity for failing to meet the system resource adequacy requirements. Under the local resource adequacy requirements, SCE must demonstrate on an annual basis that it has procured 100% of its requirement within defined local areas. The local resource adequacy requirements provide for penalties of 100% of the cost of new monthly capacity for failing to meet the local resource adequacy requirements. SCE demonstrated its compliance with the resource adequacy requirements in 2008, expects to be in compliance in 2009 and does not expect to incur any resource adequacy program penalties.

Peaker Plant Generation Projects

In August 2006, the CPUC issued a ruling addressing electric reliability needs in Southern California for summer 2007 that directed SCE, among other things, to pursue new utility-owned peaker generation that would be online by August 2007. In response, SCE pursued development of five combustion turbine peaker plants, four of which were placed online in August 2007 to help meet peak customer demands and other system requirements. In its cost recovery application for the four constructed peaker plants, SCE will revise the total recorded costs as of the end of 2008, to approximately $263 million. SCE also proposed to continue tracking the capital costs of a fifth peaker plant in the interim cost tracking mechanism approved by the CPUC and used during the construction period. Additionally, SCE proposed to file a separate cost recovery application for the fifth peaker after it is installed or its final disposition is otherwise determined (see below for further discussion on the status of the fifth peaker plant). Several parties have filed protests or other filings in response to SCE's cost recovery application. SCE expects to fully recover its costs from these peaker plants, but cannot predict the outcome of regulatory proceedings. SCE expects a CPUC decision on its cost recovery application for the first four peaker plants in 2009.

SCE has continued to pursue the construction of the fifth peaker plant. As of December 31, 2008, SCE has incurred capital costs of approximately $39 million for the fifth peaker, primarily for the purchase of the major piece of capital equipment, the combustion turbine. The required development permit for the fifth peaker plant was denied by the City of Oxnard in July 2007 and SCE appealed the denial to the California Coastal Commission. The Commission heard SCE's appeal on August 6, 2008, but did not reach a final decision. SCE expects the matter to be heard again by April 2009 but cannot predict the outcome of the appeal. SCE expects to fully recover its costs for the fifth peaker plant.

Procurement of Renewable Resources

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

It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules, such as banking of past surplus and earmarking of future deliveries from executed contracts. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

Under current CPUC decisions, potential penalties for SCE's inability to achieve its renewable procurement objectives for any year will be considered by the CPUC in the context of the CPUC's review of SCE's annual compliance filing. Under the CPUC's current rules, the maximum penalty for inability to achieve renewable procurement targets is $25 million per year. SCE does not believe it will be assessed penalties for 2008 or the prior years and cannot predict whether it will be assessed penalties for future years.

Mohave Generating Station and Related Proceedings

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Tribes. This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over post-2005 coal and water supply prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree, and there are no plans for the co-owners to return the plant to service.

The co-owners are continuing to evaluate the range of options for disposition of the plant, which conceivably could include, among other potential options, sale of the plant to a power plant operator, decommissioning of the plant and sale of the property, decommissioning and apportionment of the land among the owners, or developing in conjunction with some or all of the co-owners a renewable energy facility at the property.

SCE believed it was in full compliance with CPUC requirements and as of December 31, 2008, SCE had a Mohave net regulatory asset of approximately $54 million representing its net unamortized coal plant investment, partially offset by revenue collected for future removal costs. Based on a CPUC decision, SCE is allowed to continue to earn its authorized rate of return on the Mohave investment and receive rate recovery for amortization, costs of removal, and operating and maintenance expenses, subject to balancing account treatment. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave. The CPUC may institute an investigation to determine whether to reduce SCE's rates in light of Mohave's changed status. At this time, SCE does not anticipate that the CPUC will order a rate reduction. However, SCE cannot predict the outcome of any future CPUC action.

ISO Disputed Charges

On April 20, 2004, the FERC issued an order concerning a dispute between the ISO and the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California over the proper allocation and characterization of certain transmission service related charges. The potential cost to SCE of the FERC order, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the pertinent time, is estimated to be approximately $20 million to $25 million, including interest. The order has been the subject of continuing legal proceedings since it was issued. SCE believes that the most recent substantive order FERC has issued in the proceedings correctly allocates responsibility for these ISO charges. However, SCE cannot predict the final outcome of the rehearing. If a subsequent regulatory decision changes the allocation of responsibility for these charges, and SCE is required to pay these charges as a transmission owner, SCE may seek recovery in its reliability service rates. SCE cannot predict whether recovery of these charges in its reliability service rates would be permitted.

Market Redesign and Technology Upgrade

In early 2006, the ISO began a program to redesign and upgrade the wholesale energy market across ISO's controlled grid, known as the MRTU. The programs under the MRTU initiative are designed to implement market improvements to assure grid reliability, more efficient and cost-effective use of resources, and to create technology upgrades that would strengthen the entire ISO computer system. The CAISO has targeted the MRTU market to be operational March 31, 2009, subject to certain conditions, and filed a readiness application with the FERC in January 2009. See "Market Risk Exposures — Commodity Price Risk — Market Redesign and Technology Upgrade" for further discussion.

OTHER DEVELOPMENTS

Environmental Matters

SCE is subject to numerous federal and state environmental laws and regulations, which require them to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment. SCE believes that its operating subsidiaries are in substantial compliance with existing environmental regulatory requirements.

SCE's power plants, in particular their coal-fired plants, may be affected by recent developments in federal and state environmental laws and regulations. These laws and regulations, including those relating to SO_2 and NO_X emissions, mercury emissions, ozone and fine particulate matter emissions, regional haze, water quality, and climate change, may require significant capital expenditures at these facilities. The developments in certain of these laws and regulations are discussed in more detail below. These developments will continue to be monitored to assess what implications, if any, they will have on the operation of domestic power plants owned or operated by SCE or the impact on SCE's consolidated results of operations or financial position.

Climate Change

Federal Legislative Initiatives

Currently a number of bills are proposed or under discussion in Congress to mandate reductions of GHG emissions. At this point, it cannot be determined whether any of these proposals will be enacted into law or to estimate their potential effect on SCE's operations. The ultimate outcome of the debate about GHG emission regulation on the federal level could have a significant economic effect on SCE's operations. Any legal obligation that would require a substantial reduction in emissions of carbon dioxide or would impose additional costs or charge for the emission of carbon dioxide could have a materially adverse effect on operations.

These costs will depend upon many factors, including the required levels of GHG emission reductions, the timing of those reductions, the impact on fuel prices, whether emissions will be taxed or emission credits will be allocated with or without cost to existing generators, and whether flexible compliance mechanisms, such as a GHG offset program similar to those sanctioned under the CAA for conventional pollutants, will be part of the policy.

While debate continues at the national level over domestic climate policy and the appropriate scope and terms of any federal legislation, many states are developing state-specific measures or participating in regional legislative initiatives to reduce GHG emissions.

Edison International, SCE's parent holding company, supports a national regulatory program for GHG emission reduction that is market-based, equitable and comprehensive, through which all sources of GHG emissions are regulated and all certifiable means of reducing and offsetting such emissions are recognized. This program should be long-term, and should establish technologically realistic GHG emission reduction targets.

Regional Initiatives

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a-cap-and trade GHG program for electric generators, referred to as the Regional Greenhouse Gas Initiative (RGGI). In August 2006, the participating states issued a model rule to be used as a basis for individual state legislative and regulatory action to implement the program. The RGGI states (now numbering ten states) have passed laws and/or regulations to implement the RGGI program, which commenced in 2009.

In February 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington launched the Western Climate Initiative to develop regional strategies to address climate change. The Western Climate Initiative is identifying, evaluating and implementing collective and cooperative ways to reduce greenhouse gases in the region. Since February 2007, the Governor of Utah and Montana and the Premiers of British Columbia, Manitoba, Ontario and Quebec have joined the Initiative. Other states and provinces have joined as observers. The Initiative partners set an overall regional goal in August 2007 for reducing GHG emissions to 15% below 2005 levels by 2020. In September 2008, the partners released design recommendations for the regional cap-and-trade program intended to help achieve that reduction goal.

The Midwestern Accord seeks to develop regional GHG emission reduction goals within one year, and to develop a multi-sector cap-and-trade program to achieve these goals. The Accord called for such a program to be implemented in 30 months. On February 19, 2008, the six participating states announced that they would complete a model rule by the end of 2008 that would create the framework for the cap-and-trade program. The schedule for the model rule has been revised to fall 2009. Once this model rule has been drafted, each of the participating states could adopt the program through legislative action, executive order or other appropriate means.

Implementing regulations for such regional initiatives are likely to vary from state to state and may be more stringent and costly than federal legislative proposals currently being debated in Congress. It cannot yet be determined whether or to what extent any federal legislative system would seek to preempt regional or state initiatives, although such preemption would greatly simplify compliance and eliminate regulatory duplication.

State-Specific Legislation

In September 2006, California enacted two laws regarding GHG emissions. The first, known as AB 32 or the California Global Warming Solutions Act of 2006, establishes a comprehensive program to begin in 2012 to achieve reductions of GHG emissions. The second law, known as SB 1368, required the CPUC and the CEC, respectively, to adopt GHG emission performance standards, known as EPS, for investor owned and publicly owned utilities, respectively, for long-term procurement of electricity. These standards must equal the performance of a combined-cycle gas turbine generator.

AB 32 required the CARB to approve a scoping plan for achieving the maximum technologically feasible and cost-effective reductions in GHG emissions on or before January 1, 2009. On December 11, 2008, the CARB approved a proposed scoping plan which was largely unchanged from the original draft scoping plan that was released in June 2008. However, the revised draft scoping plan does not include the more aggressive energy efficiency or coal emission reduction standard measures that were under evaluation for inclusion in the proposed draft scoping plan. The preliminary recommendations in the proposed scoping plan included: a California cap-and-trade program linked to the Western Climate Initiative covering electricity, transportation, residential/commercial, and industrial sources by 2020; California light-duty vehicle GHG standards; increased energy efficiency, including increasing combined heat and power use; a 33% by 2020 Renewables Portfolio Standard for both Investor-Owned Utilities and publicly-owned utilities; a low-carbon fuel standard; measures to reduce high global warming potential gases; sustainable forest measures; water sector measures; vehicle efficiency measures, goods movement measures; heavy/medium duty vehicle measures; the Million Solar Roofs program; local government actions and regional targets; supporting implementation of a high-speed rail system; recycling and waste measures; agriculture measures; and energy efficiency and co-benefits audits for large industrial sources.

In October 2008, the CPUC and CEC adopted a proposed opinion on GHG regulatory strategies providing additional recommendations to the CARB on measures and strategies for reducing GHG emissions in the electricity and natural gas sectors. The proposed opinion's recommendations address mandatory emission reduction measures including energy efficiency, renewable resources, and expansion of combined heat and power. The recommendations also include design suggestions for a multi-sector, statewide, cap-and-trade program. The Los Angeles Department of Water and Power filed a request for rehearing and reconsideration of the opinion with the CPUC and CEC on November 21, 2008.

AB 32 also required the CARB to adopt regulations requiring the reporting and verification of statewide GHG emissions on or before January 1, 2008. On December 6, 2007 the CARB approved regulations for the mandatory reporting of GHG emissions, including the reporting of GHG emissions for the electricity sector. The CARB directed its staff to make some technical modifications to the proposed regulations, which had been issued in October 2007. The CARB staff issued revised regulations for public comment on May 15 and June 30, 2008. The final regulations became effective on January 1, 2009. SCE is evaluating the CARB's reporting regulations and the scoping plan under AB 32 to assess the total cost of compliance.

The emission performance standards adopted by the CPUC and CEC pursuant to SB 1368 prohibit SCE and other California load-serving entities from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, which would include most coal-fired plants. In January 2008, SCE filed a petition with the CPUC seeking clarification that the emission performance standard would not apply to capital expenditures required by existing agreements among the owners at Four Corners. The CPUC issued a proposed decision finding that the emission performance standard was not intended to apply to capital expenditures at Four Corners requested by SCE in its GRC for the period 2007 — 2011. In October 2008, the Assigned Commissioner and Administrative Law Judge issued a ruling withdrawing the proposed decision and seeking additional comment on whether the finding in the proposed decision should be changed and whether SCE should be allowed to recover such capital expenditures. SCE estimates that its share of capital expenditures approved by the owners at Four Corners since the GHG emission performance standard decision was issued in January 2007 is approximately $43 million, of which approximately $8 million had been expended through December 31, 2008. The ruling also directs SCE to explain why certain information was not included in its petition and why the failure to include such information should not be considered misleading in violation of CPUC rules. SCE filed its response and comments to the ruling in November and December 2008 and cannot predict the outcome of this proceeding or estimate the amount, if any, of penalties or disallowances that may be imposed.

Litigation Developments

Significant climate change litigation, raising issues that may affect the timing and scope of future GHG emission regulation, was brought by a variety of public and private parties in the past several years. As no decisions were handed down in any of the major cases in 2008, it continues to be difficult to determine how the courts will respond to every situation. To date, trial courts that have addressed the cases in which plaintiffs have sought damages or equitable relief directly from power companies and other defendants have dismissed the plaintiff's claims, either because the courts determined that a judicial decision would impermissibly intrude on the powers of the legislative and executive branches to regulate and, as applicable, enter into foreign compacts concerning GHG emissions, or because of the absence of evidence linking any individual defendant's GHG emissions to any harm allegedly incurred by the suing plaintiffs.

On April 2, 2007, the United States Supreme Court issued an opinion in Massachusetts et. al. v. Environmental Protection Agency, et. al., ruling that the US EPA has the authority to regulate GHG emissions of new motor vehicles under the CAA and that it has a duty to determine whether GHG emissions of new motor vehicles contribute to climate change or offer a reasoned explanation for its failure to make such a determination when presented with a request for a rulemaking on the issue by the state claimants. The Court ruled that the US EPA's failure to make the necessary determination or to offer a reasonable explanation for its refusal to do so was impermissible. While this case hinged on a provision of the CAA related to emissions of motor vehicles, a parallel provision of the CAA applies to stationary sources, such as electric generators, and there is litigation pending in the D.C. Circuit Court of Appeals, Coke Oven Task Force v. EPA, in which it is argued that the Massachusetts v. EPA case may be applied to stationary sources such as power plants.

In April 2006, private citizens filed a complaint in federal court in Mississippi against numerous defendants, including Edison International, SCE's parent company, and several electric utilities, arguing that emissions from the defendants' facilities contributed to climate change and seeking monetary damages related to the 2005 hurricane season. In August 2007, the court dismissed the case, and plaintiffs have appealed this dismissal to the Fifth Circuit Court of Appeals. In February 2008, a native Alaskan village and city filed a complaint in federal court in California against 24 defendants, including Edison International, who directly or through subsidiaries engage in electric generating, oil and gas, or coal mining lines of business. The complaint contends that the alleged global warming impacts of the GHG emissions associated with the defendants' business activities are destroying the plaintiffs' village through the melting of Arctic ice that had previously protected the village from winter storms. The plaintiffs further allege that the village will soon need to be abandoned or relocated at a cost of between $95 million and $400 million. Motions to dismiss the complaint in the California case are currently pending and SCE cannot predict the outcome of this lawsuit.

Air Quality Regulation

Clean Air Interstate Rule

The CAIR, issued by the US EPA on March 10, 2005, applies to 28 eastern states and the District of Columbia, and is intended to address ozone and fine particulate matter attainment issues by reducing regional SO_2 and NOx emissions. The CAIR reduces the current CAA Title IV Phase II SO_2 emissions allowance cap for 2010 and 2015 by 50% and 65%, respectively. The CAIR also requires reductions in regional NO_X emissions in 2009 and 2015 by 53% and 61%, respectively, from 2003 levels. The CAIR has been challenged in court by state, environmental and industry groups, which may result in changes to the substance of the rule and to timetables for implementation.

The US EPA's CAIR currently does not apply to SCE's facilities. While the US EPS has not adopted a rule comparable to CAIR for the western Untied States where SCE has facilities, SCE cannot predict what action the US EPA will take in the future with regard to the western United States, and what impact those actions would have on its facilities.

Clean Air Mercury Rule

By means of a rule published in May 2005, the US EPA established the CAMR, which created the framework for a national, market-based cap-and-trade program to reduce mercury emissions from existing coal-fired power plants to a national cap of 38 tons by 2010 and to 15 tons by 2018, primarily through reductions in mercury achieved by lowering SO_2 and NOx emissions under the CAIR. States were allowed, but not required, to join the trading program by adopting the CAMR model trading rules. States retained the right to promulgate alternative regulations equivalent to or more stringent than the CAMR cap-and-trade program, as long as the regulations were approved by the US EPA.

At the time that it published the CAMR, the US EPA also published a second rule, formally rescinding its previous finding that mercury emissions from electrical generating facilities had to be regulated as a hazardous air pollutant pursuant to Section 112 of the CAA, which would have imposed technology-based standards on emission sources. Both the CAMR and the US EPA's decision to remove oil- and coal-fired plants from the list of sources to be regulated under Section 112 of the CAA were challenged in the U.S. Court of Appeals for the D.C. Circuit by various environmental groups and state attorneys general.

On February 8, 2008, the D.C. Circuit Court of Appeals vacated both rules and remanded the matter to the US EPA. The United States and the Utility Air Regulatory Group had petitioned the Supreme Court to review the D.C. Circuit's decision, but the United States subsequently filed a motion to withdraw its petition based on a determination by the US EPA to develop a new mercury regulation pursuant to Section 112 of the CAA. The Utility Air Regulatory Group has not withdrawn its petition. The order has been appealed to the U.S. Supreme Court. Until the US EPA takes action in response to the remand, coal-fired electrical generating units will continue to be sources subject to the requirements of Section 112 of the CAA and will be obligated to comply, on a case-by-case basis, with technology-based standards to control emissions of all hazardous air pollutants (not necessarily limited to mercury) in accordance with the requirements of Section 112.

Regional Haze

In July 1999, the US EPA published the "Regional Haze Rule" to reduce haze and protect visibility in designated federal areas. The goal of the 1999 rule 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 (also known as BART) or implement other control strategies to meet regional haze control requirements. States were required to revise their SIPs by December 2007 to demonstrate reasonable further progress towards meeting regional haze goals.

On January 9, 2009, the US EPA found that 37 states, including California and Nevada, had failed to submit all or a portion of their regional haze SIPs. For those states that have yet to make a submission, or that have made a submission that does not include particular SIP elements, EPA is making a "finding of failure to submit." The US EPA finding initiates a 2-year deadline for EPA to issue a Federal Implementation Plan or FIP. The FIP will provide the basic program requirements for each State that has not completed an approved plan of its own by January 15, 2011.

The US EPA has adopted alternate rules for the area where Four Corners is located. The rules allow nine western states and Native American tribes to follow an alternate implementation plan and schedule for the Class I Areas. This alternate implementation plan is known as the Annex Rule.

New Mexico

The Regional office of the US EPA (EPA Region 9) requested that Arizona Public Service Company perform a BART analysis for Four Corners. This analysis was completed and submitted it to the US EPA on January 30, 2008. The EPA Region 9 will review Arizona Public Service Company's submission and determine what constitutes BART for Four Corners. Once Arizona Public Service Company receives the EPA Region 9's final determination, it will have five years to complete the installation of the equipment and to achieve the emission limits established by the EPA Region 9. Until the EPA Region 9 makes a final determination on this matter, SCE cannot accurately estimate the expenditures that may be required. SCE also cannot predict whether the relevant environmental agencies will agree with its BART recommendations or, if the agencies disagree with our recommendations, the nature of the BART controls the agencies may ultimately mandate and the resulting financial or operational impact.

Ambient Air Quality Standards

The US EPA designated non-attainment areas for its 8-hour ozone standard on April 30, 2004, and for its fine particulate matter standard on January 5, 2005. States were required to revise their SIPs for the ozone and particulate matter standards within three years of the effective date of the respective non-attainment designations. Since then, the US EPA has issued more stringent 24-hour fine particulate and ground level ozone standards. The revised SIPs are likely to require additional emission reductions from facilities that are significant emitters of ozone precursors and particulates. SCE anticipates that further emission reduction obligations will not be imposed under these revised ambient air quality standards until 2015.

Priority Reserve Legal Challenges

In July 2008, the Los Angeles Superior Court found that actions taken by the SCAQMD in promulgating rules that had made available a "Priority Reserve" of emissions credits for new power generation projects did not satisfy California environmental laws. Accordingly, in November 2008, the Superior Court enjoined the SCAQMD from issuing Priority Reserve emission credits to any facility, including new power projects, until a satisfactory environmental analysis is completed. The writ also ordered the SCAQMD to refrain from taking any action relating to power plant projects approved after August 2007 pursuant to the Priority Reserve rules until the SCAQMD completes a satisfactory environmental analysis. The SCAQMD appealed the Superior Court decision, and in doing so, stayed the injunction against the issuance of permits.

In a letter dated January 9, 2009, which was sent to numerous permit holders, the SCAQMD stated that it "cannot ensure the long-term validity of permits issued on or after August 3, 2007, or possibly on or after September 8, 2006" because the issuance of credits from the Priority Reserve may be considered invalid. As a result, the permits for SCE's four constructed peaker plants, which were issued in March and April 2007 may be in jeopardy (see "Regulatory Matters — Current Regulatory Developments — Peaker Plant Generation Projects" for further information). However, because the SCAQMD's appeal of the Superior Court decision resulted in the Superior Court's injunction being stayed, existing permits will remain in effect pending the appeal.

Separately, in August 2008, substantially the same plaintiffs sued the SCAQMD in federal court alleging that the emission credits contained in SCAQMD's New Source Review offset accounts (which include the Priority Reserve) are invalid and seeking to enjoin SCAQMD from transferring them. The SCAQMD has filed a motion to dismiss the federal suit. SCE has joined a coalition of other interested parties that have intervened in the federal litigation between the SCAQMD and environmental groups.

SCE is in the process of evaluating the impact of the two lawsuits on certain power-purchase agreements that resulted from its new generation RFO and the potential implications for its long-term resource adequacy requirements.

Water Quality Regulation

Clean Water Act — Prohibition on the Use of Ocean-Based Once-Through Cooling

On March 21, 2008 the California State Water Resources Control Board released its draft scoping document and preliminary draft Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. This state policy is being developed in advance of the issuance of a final rule from the

US EPA on standards for cooling water intake structures at existing large power plants. As anticipated, the Scoping Document establishes closed-cycle wet cooling as the best technology available for retrofitting existing once-through cooled plants like San Onofre. Additionally, the target levels for compliance with the state policy correspond to the high end of the ranges originally proposed in the US EPA's rule. Nuclear-fueled power plants, including San Onofre, would have until January 1, 2021 to comply with the policy. The policy development schedule included in the scoping document scheduled workshops and the submission of public comments in May 2008 and a public hearing in September 2008. The State Board vote has been informally delayed and is currently anticipated to occur in late 2009. SCE continues to work with key government policy makers. This policy may significantly impact both operations at San Onofre and SCE's ability to procure timely supplies of generating capacity from fossil-fueled plants that use ocean water in once-through cooling systems.

Proposed California Senate Bill

In January 2009, a bill (SB 42) was introduced in the California State Senate which would prohibit power plants and other industrial facilities from using once-through cooling methods on or after January 1, 2015. For the period from January 1, 2011 to December 31, 2014 any power plant or other facility using once-through cooling methods would be required to pay a seawater fee of $0.15 per 10,000 gallons used. The cost to San Onofre for the use of seawater for Units 2 and 3 would total approximately $12 million annually. SCE and Edison International oppose this bill because it does not take into account environmental, economic or grid reliability impacts.

Electric and Magnetic Fields

In January 2006, the CPUC issued a decision updating its policies and procedures related to EMF emanating from regulated utility facilities. The decision concluded that a direct link between exposure to EMF and human health effects has yet to be proven, and affirmed the CPUC's existing "low-cost/no-cost" EMF policies to mitigate EMF exposure for new utility transmission and substation projects.

Environmental Remediation

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

SCE believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that SCE's financial position and results of operations would not be materially affected.

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

As of December 31, 2008, SCE's recorded estimated minimum liability to remediate its 24 identified sites was $41 million, of which $10 million was related to San Onofre. This remediation liability is undiscounted. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $173 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $40 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $31 million. Recorded costs were $29 million, $25 million and $14 million for 2008, 2007 and 2006, 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 or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

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

In the normal course, Edison International's federal income tax returns are examined by the IRS and Edison International challenges deficiency adjustments, asserted as part of an examination, to the Administrative Appeals branch of the IRS (IRS Appeals) to the extent Edison International believes its tax reporting positions properly complied with the relevant tax law and that the IRS' basis for making such adjustments lacks merit. Edison International has challenged certain IRS deficiency adjustments, asserted as part of the examination of tax years 1994 – 1999 with IRS Appeals. Edison International has also been under active IRS examination for tax years 2000 – 2002 and during the third quarter of 2008, the IRS commenced an examination of tax years 2003 – 2006. In addition, the statute of limitations remains open for tax years 1986 – 1993, which has allowed Edison International to file certain affirmative claims related to these tax years.

Most of the tax positions that Edison International is addressing with IRS Appeals relate to the timing of when deductions for federal income tax purposes are allowed to be reflected on filed income tax returns and, as such, any deductions not sustained would be deductible on future tax returns filed by Edison International. However, any penalties and interest associated with disallowed deductions would result in a permanent cost. Edison International has also filed affirmative claims with respect to certain tax years 1986 through 2005 with the IRS and state tax authorities. At this time, there has not been a final determination of these affirmative claims by the IRS or state tax authorities. Benefits, if any, associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when Edison International would make an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement of the affirmative claim is consummated with the tax authority. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

Edison International has been engaged in settlement negotiations with the IRS to reach a Global Settlement described below of all unresolved tax disputes and affirmative claims for tax years 1986 – 2002.

In addition to the IRS audits, Edison International's California and other state income tax returns are, in the normal course, subjected to examination by the California Franchise Tax Board and the other state tax authorities. The Franchise Tax Board has substantially completed its examination of all tax years through 2002 and is currently awaiting resolution of the IRS audit before finalizing the audit for these tax years. Edison International is currently under active examination for tax years 2003 – 2004 and remains subject to examination by the California Franchise Tax Board for tax years 2005 and forward.

Edison International filed amended California Franchise tax returns for tax years 1997 – 2002 to mitigate the possible imposition of California non-economic substance penalty provisions on transactions that may be considered as Listed or substantially similar to Listed Transactions described in an IRS notice that was published in 2001. These transactions include an SCE subsidiary contingent liability company transaction, described below. Edison International filed these amended returns under protest retaining its appeal rights.

Global Settlement

As previously disclosed, Edison International has negotiated the material terms of a Global Settlement with the IRS which, if consummated, would resolve all outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. Consummation of the Global Settlement is subject to review by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee"). The IRS submitted the pertinent terms of the Global Settlement to the Joint Committee during the fourth quarter of 2008, and its response is currently pending. Edison International cannot predict the timing of when the Joint Committee will complete its review. Moreover, Edison International cannot predict whether the Joint Committee will concur with the settlement terms negotiated by the IRS for the Global Settlement issues and whether any non-concurrence would result in the IRS proposing different settlement terms.

If and when Edison International and the IRS consummate a settlement, Edison International will file amended tax returns with the Franchise Tax Board and other state administrative agencies, for those states in which Edison International has an income tax filing requirement, to reflect the respective state income tax impact of the settlement terms.

The issues discussed below are included in the ongoing IRS examination and appeals process and are included in the scope of issues being addressed as part of the Global Settlement process.

Balancing Account Over-Collections

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

Contingent Liability Company

The IRS has asserted tax deficiencies and penalties of $53 million and $22 million, respectively, for tax years 1997 – 1999 with respect to a transaction entered into by a former SCE subsidiary which the IRS has asserted to be substantially similar to a Listed Transaction described by the IRS as a contingent liability company.

Palo Verde Nuclear Generating Station Inspection

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

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the District Court against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion. In March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff but has not yet identified a specific amount of damages claimed. The case was stayed at the request of the parties in October 2004, but was reinstated to the active calendar in March 2008.

A related case against the U.S. Government is presently before the U.S. Supreme Court. The outcome of that case could affect the Navajo Nation's pursuit of claims against SCE. A decision from the U.S. Supreme Court is expected in mid-2009.

SCE cannot predict the outcome of the Tribe's complaints against SCE or the ultimate impact on these complaints of the on-going litigation by the Navajo Nation against the U.S. Government in the related case.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre (approximately $24 million, plus interest). SCE has also been paying a required quarterly fee equal to 0.1¢ per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Such interim storage for San Onofre is on-site.

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

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site.

Federal regulations require this secondary level of financial protection. The NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. Beginning October 29, 2008, the maximum deferred premium for each nuclear incident is approximately $118 million per reactor, but not more than approximately $18 million per reactor may be charged in any one year for each incident. The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident is adjusted for inflation at least once every five years. The most recent inflation adjustment took effect on October 29, 2008. Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further operating revenue.

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

Wildfire Insurance Issues

Recent, severe wildfires in California have given rise to very large damage claims against California utilities. Additionally, California law includes a doctrine of inverse condemnation that imposes strict liability (including liability for a claimant's attorneys' fees) for fire damage caused to private property by SCE's electric facilities that serve the public. SCE currently is insured for such liabilities up to a limit of $650 million (with a $2 million self-insured retention) until September 2009. The strict liability standard and the apparent rising trend in wildfire occurrences and intensity may affect SCE's ability to obtain comparable insurance levels at comparable cost in the future, and there can be no assurance that SCE would be allowed to recover in customer rates the increased cost of such insurance or the cost of any uninsured losses. In addition, the CPUC investigates fires that may have been caused by a utility's facilities, and, if violations of CPUC regulations are found, the CPUC may penalize the utility.

LIQUIDITY

Overview

As of December 31, 2008, SCE had cash and equivalents of $1.6 billion ($89 million of which was held by SCE's consolidated VIEs). As a reaction to significant disruption in the credit and capital markets, SCE borrowed against its credit facility and issued bonds in October 2008 to ensure the availability of funds to meet its future cash requirements. The proceeds were invested in U.S. treasury bills and U.S. treasury and government agency money market funds. This credit line draw is recorded as short-term debt, as it is expected to be re-paid by year-end 2009.

In March 2008, SCE amended its existing $2.5 billion credit facility, extending the maturity to February 2013 while retaining existing borrowing costs as specified in the facility. The amendment also provides four extension options which, if all exercised, and agreed to by the lenders, will result in a final termination in February 2017. During February 2009, SCE has been negotiating with several banks to potentially increase its liquidity facilities by an additional $500 million. The consummation of such negotiations is subject to the availability of additional bank credit capacity on commercially feasible terms. Such liquidity would be used to address potential requirements of SCE's ongoing procurement-related needs.

A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB, is one of the lenders in SCE's credit agreement representing a total commitment of $106 million. Lehman Brothers Bank, FSB, had funded $25 million of a borrowing request during the second quarter of 2008. On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Lehman Brothers Bank, FSB, declined requests for funding of approximately $57 million during the second half of 2008.

The following table summarizes the status of the SCE credit facility at December 31, 2008:

In millions	SCE
Commitment	$ 2,500
Less: Unfunded commitment from Lehman Brothers subsidiary	(81)
	2,419
Outstanding borrowings	(1,893)
Outstanding letters of credit	(141)
Amount available	**$ 385**

As of December 31, 2008, SCE's long-term debt, including current maturities of long-term debt, was $6.4 billion. In October 2008, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014.

SCE's estimated cash outflows during the 12-month period following December 31, 2008 are expected to consist of:

- Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct and replace major components of generation assets (see "— Capital Expenditures" below);
- Fuel and procurement-related costs (see "Regulatory Matters — Current Regulatory Developments — Energy Resource Recovery Account Proceedings"), including collateral requirements (see "— Margin and Collateral Deposits");
- In December 2008 the Board of Directors of SCE declared a $100 million dividend to Edison International which was paid in January 2009. As a result of SCE's cash requirements, including its capital expenditures plan, SCE does not expect to declare additional dividends to Edison International in 2009;
- Maturity and interest payments on short- and long-term debt outstanding;
- General operating expenses; and

- Pension and PBOP trust contributions (see "— Pension and PBOP trusts" below).

As discussed above, SCE expects to meet its 2009 continuing obligations, including cash outflows for operating expenses and power-procurement, through cash and equivalents on hand and operating cash flows. Projected 2009 capital expenditures are expected to be financed through cash and equivalents on hand, operating cash flows and incremental capital market financings of debt and preferred equity. SCE expects that it would also be able to draw on the remaining availability of its credit facility and access capital markets if additional funding and liquidity is necessary to meet the estimated operating and capital requirements, but given current market conditions there can be no assurance of such credit and capital availability.

On February 13, 2008, President Bush signed the Economic Stimulus Act of 2008 (2008 Stimulus Act). The 2008 Stimulus Act includes a provision that provides accelerated bonus depreciation for certain capital expenditures incurred during 2008. Edison International expects that certain capital expenditures incurred by SCE during 2008 will qualify for this accelerated bonus depreciation, which would provide additional cash flow benefits estimated to be approximately $110 million for the 2008 tax return. On February 17, 2009, President Obama signed the American Recovery and Reinvestment Act of 2009 which extended the accelerated bonus depreciation provision through the end of 2009. Edison International expects that certain capital expenditures incurred by SCE during 2009 will qualify for this accelerated bonus depreciation.

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

Capital Expenditures

SCE has planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. As previously discussed, the CPUC has issued an Administrative Law Judge's proposed decision, as well as a revised alternate proposed decision on SCE's 2009 GRC. The two proposed decisions provide for different levels of capital expenditures. Based on the revised alternate proposed decision and reflecting a level of variability (discussed below), SCE's 2009 through 2013 capital investment plan includes capital spending in the range of $17.1 billion to $21 billion. The Administrative Law Judge's proposed decision, if adopted, would further reduce the range of capital spending by approximately $2.8 billion related to a $2.0 billion modeling error which authorizes a specified level of capital expenditures, but does not provide the revenue requirement to recover a portion of these capital expenditures beginning in 2010 and an $800 million reduction in the level of capital expenditures. Recovery of the CPUC jurisdictional 2009 through 2011 planned expenditures primarily is subject to CPUC approval in SCE's 2009 GRC application. Recovery of certain other projects included in the 2009 through 2011 investment plan has been approved or will be requested and approved through other CPUC-authorized mechanisms on a project-by-project basis. These projects include, among others, SCE's SmartConnect advanced metering infrastructure project, the San Onofre steam generator replacement project, and the solar photovoltaic program. SCE plans total investments for 2009 through 2013 to be $1.2 billion, $450 million and $880 million, for each of these projects, respectively. SCE's GRC related expenditures for 2012 and 2013 are subject to future approval. Recovery of the 2009 through 2013 planned transmission expenditures for FERC-jurisdictional projects have been requested in the 2009 FERC Rate Case proceeding, or will be requested in future transmission filings with the FERC.

SCE's 2008 capital expenditures (including accruals) were $2.4 billion related to its 2008 capital plan. SCE's 2008 capital expenditures were less than the forecast for 2008 of $2.9 billion, primarily due to delays in transmission investments as well as other timing delays. Developments in the financial markets, regulatory decisions, and economic conditions in the U.S. may also alter SCE's future capital expenditures plans. See "Edison International: Management Overview — Areas of Business Focus — Financial Markets and Economic Conditions" for further discussion. The completion of the projects, the timing of expenditures, and the associated recovery may be affected by permitting requirements and delays, construction delays, availability of labor, equipment and materials, financing, legal and regulatory developments, weather and other unforeseen conditions. The estimated capital expenditures for the next five years may vary from SCE's current forecast. If SCE assumes the same level of variability to forecast experienced in 2008 (approximately 18%), SCE's 2009 forecast would vary in the range of $2.9 billion to $3.6 billion. If the Administrative Law Judge's proposed decision is adopted, the 2009 forecast would be reduced by approximately $800 million resulting from a $600 million modeling error and a $200 million reduction in the level of capital expenditures, both discussed above.

Included in SCE's capital investment plan are projected environmental capital expenditures of $476 million in 2009 and approximately $2.1 billion for the period 2010 through 2013. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines at SCE.

Solar Photovoltaic Program

On March 27, 2008, SCE filed an application with the CPUC to implement its Solar Photovoltaic (PV) Program to develop up to 250 MW of utility-owned Solar PV generating facilities ranging in size from 1 to 2 MW each on commercial and industrial rooftop space in SCE's service territory. Subject to CPUC approval, the capital expenditures will be eligible to be included in SCE's earning asset base if the actual costs of the program are equal to or lower than the reasonableness threshold amount of $963 million in nominal dollars. SCE also proposes to apply a CPUC-established 100 basis point incentive adder to SCE's allowed rate of return on rate base on the project. In September 2008, the CPUC granted SCE's request to track costs spent on projects up to $25 million incurred prior to the receipt of the CPUC's final decision in a memorandum account for potential future recovery. SCE has spent $12 million as of December 31, 2008. SCE completed its first 2 MW project in December 2008, and expects to continue to move forward with two other projects in advance of the final CPUC decision subject to the authorized tracking account mechanism. In September 2008, several parties filed testimony opposing SCE's Solar PV program application. Evidentiary hearings took place in November 2008 and a final decision is expected in March 2009. SCE cannot predict the final outcome of this proceeding.

EdisonSmartConnect^{tm}

SCE's EdisonSmartConnect^{tm} project involves installing state-of-the-art "smart" meters in approximately 5.3 million households and small businesses through its service territory. The development of this advanced metering infrastructure is expected to be accomplished in three phases: the initial design phase to develop the new generation of advanced metering systems (Phase I), which was completed in 2006; the pre-deployment phase (Phase II) to field test and select EdisonSmartConnect^{tm} technologies, select the deployment vendor and finalize the EdisonSmartConnect^{tm} business case for full deployment, which was completed in December 2007; and the final deployment phase (Phase III), to deploy meters to all residential and small business customers under 200 kW over a five-year period. SCE applied to the CPUC in July 2007 to request authority to deploy the program and began deployment activities in 2008. In March 2008, SCE reached a full settlement of the Phase III issues with the DRA and in September 2008, the CPUC approved the settlement, authorizing SCE to recover $1.63 billion in ratepayer funding for the Phase III deployment of EdisonSmartConnect^{tm}. SCE expects to begin deployment of meters in 2009, and anticipates completion of the deployment in 2012. The total cost for this project, including Phase II pre-deployment, is estimated to be $1.7 billion of which $1.25 billion is estimated to be capitalized and included in utility rate base. The remaining book value for SCE's existing meters at December 31, 2008 is $398 million. SCE expects to recover the remaining book value of the existing meters, with a return, over their remaining lives through its 2009 GRC application.

Pension and PBOP Trusts

Volatile market conditions have affected the value of SCE's trusts established to fund its future long-term pension benefits and other postretirement benefits. The fair value of the investments (reflecting investment performance, contributions and benefit payments) within the pension and PBOP plan trusts declined 35% and 33%, respectively, during 2008. These benefit plan assets and related obligations are remeasured annually using a December 31 measurement date. The plans' funded status is recorded on the balance sheet in accordance with SFAS No. 158. Due to the reductions in the value of plan assets, the pension and PBOP plans were underfunded $937 million and $1 billion at December 31, 2008, respectively. Forecast expense in 2009 and contributions for the 2009 plan year are expected to increase by approximately $150 million. SCE is authorized to recover these costs through customer rates, therefore recognition of the funded status of SCE's plans is offset by regulatory assets of $1.9 billion. In the 2009 GRC, SCE requested continued balancing account treatment for amounts contributed to these trusts and requested that these amounts be collected annually (see "Regulatory Matters — Current Regulatory Developments — 2009 General Rate Case Proceeding" for further discussion). In response to the volatile market conditions, the trusts' investment committees have implemented interim lower equity allocation targets and continue to assess the long-term asset allocation strategies. The Pension Protection Act of 2006 established minimum funding standards and restricts plan payouts if underfunded by more than 20%, limiting provisions for lump-sum distributions and adopting amendments that increase plan liabilities.

Nuclear Decommissioning Trusts

Volatile market conditions have also affected the value of SCE's trusts established to fund nuclear decommissioning obligations. SCE is collecting in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The next filing is in April 2009 for contribution changes in 2011. The significant decrease recently experienced in the nuclear decommissioning trust assets, is expected, absent a market recovery, to impact the CPUC established contributions for 2011. In response to the volatile market conditions, the trusts' investment committees have implemented interim lower equity allocation targets and continue to assess the long-term asset allocation strategies. See "Critical Accounting Estimates and Policies — Nuclear Decommissioning" for further information.

Trust investments (at fair value) are as follows:

In millions	Maturity Dates	December 31, 2008	December 31, 2007
Municipal bonds	2009 – 2044	**$ 629**	$ 561
Stocks	–	**1,308**	1,968
United States government issues	2009 – 2049	**304**	552
Corporate bonds	2009 – 2047	**260**	241
Short-term investments, primarily cash equivalents	2009	**23**	56
Total		**$ 2,524**	$ 3,378

Note: Maturity dates as of December 31, 2008.

The following table sets forth a summary of changes in the fair value of the trust for December 31, 2008:

In millions	December 31, 2008
Balance at beginning of period	$ 3,378
Realized losses – net	(65)
Unrealized losses – net	(545)
Other-than-temporary impairment	(317)
Earnings and other	73
Balance at December 31, 2008	**$ 2,524**

Credit Ratings

At December 31, 2008, SCE's credit ratings were as follows:

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

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

Dividend Restrictions and Debt Covenants

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. 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 authorized level on a 13-month weighted average basis of 48%. At December 31, 2008, SCE's 13-month weighted-average common equity component of total capitalization was 50.6% resulting in the capacity to pay $345 million in additional dividends.

SCE has a debt covenant in its credit facility that requires a debt to total capitalization ratio of less than or equal to 0.65 to 1 to be met. At December 31, 2008, SCE's debt to total capitalization ratio was 0.53 to 1.

Margin and Collateral Deposits

SCE has entered into certain margining agreements for power and natural gas trading activities in support of its procurement plan as approved by the CPUC. SCE's margin deposit requirements under these agreements can vary depending upon the level of unsecured credit extended by counterparties and brokers, changes in market prices relative to contractual commitments, and other factors. Future collateral requirements may be higher (or lower) than collateral requirements at December 31, 2008, due to the addition of incremental power and energy procurement contracts with margining agreements, if any, and the impact of changes in wholesale power and natural gas prices on SCE's contractual obligations. Certain requirements to post cash and/or collateral (primarily for changes in fair value and accounts payables on delivered energy transactions) would be triggered if SCE's credit ratings were downgraded to below investment grade, as indicated in the table below.

In millions	
Collateral posted as of December 31, 2008[1]	$ 230
Incremental collateral requirements resulting from a potential downgrade of SCE's credit rating to below investment grade	186
Total posted and potential collateral requirements[2]	**$ 416**

(1) Collateral posted consisted of $72 million which were offset against net derivative liabilities in accordance with the implementation of FIN 39-1, and $158 million provided to counterparties and other brokers (consisting of $17 million in cash reflected in "Margin and collateral deposits" on the consolidated balance sheets and $141 million in letters of credit).

(2) Total posted and potential collateral requirements may increase by an additional $124 million, based on SCE's forward position as of December 31, 2008, due to adverse market price movements over the remaining life of the existing contracts using a 95% confidence level.

SCE's incremental collateral requirements are expected to be met from liquidity available from cash on hand and available capacity under SCE's $2.5 billion credit facility, discussed above.

MARKET RISK EXPOSURES

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

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes, to fund business operations and to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. In addition, SCE's authorized return on common equity (11.5% for 2009 and 2008 and 11.6% for 2007), which is established in SCE's cost of capital proceeding, is set on the basis of forecasts of interest rates and other factors. Variances in actual financing costs compared to authorized financing costs either positively or negatively impact earnings. See "Regulatory Matters — Base Rates" for further discussion on SCE's recoverability of financing costs.

At December 31, 2008, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. At December 31, 2008, the fair market value of SCE's long-term debt (including long-term debt due within one year) was $6.7 billion, compared to a carrying value of $6.4 billion. A 10% increase in market interest rates would have resulted in a $336 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 $368 million increase in the fair market value of SCE's long-term debt.

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

Commodity Price Risk

Introduction

SCE is exposed to commodity price risk from its purchases of additional capacity and ancillary services to meet peak energy requirements and from exposure to natural gas prices that affect costs associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including SCE's Mountainview plant. Contract energy prices for most nonrenewable QFs are based in large part on the monthly southern California border price of natural gas. In addition to the QF contracts, SCE has power contracts in which SCE has agreed to provide the natural gas needed for generation under those power contracts, which are referred to as tolling arrangements. In addition to SCE's Mountainview and peaker plants, approximately 46% of SCE's power purchase requirements are subject to natural gas price volatility.

The CPUC has established resource adequacy requirements which require SCE to acquire and demonstrate enough generating capacity in its portfolio for a planning reserve margin of 15 – 17% above its peak load as forecast for an average year (see "Regulatory Matters — Current Regulatory Developments — Resource Adequacy Requirements"). The establishment of a sufficient planning reserve margin mitigates, to some extent, exposure to commodity price risk for spot market purchases.

SCE's purchased-power costs and gas expenses, as well as related hedging costs, are recovered through the ERRA. To the extent SCE conducts its power and gas procurement activities in accordance with its CPUC-authorized procurement plan, California statute (Assembly Bill 57) establishes that SCE is entitled to full cost recovery. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but are not expected to affect earnings. Certain SCE activities, such as contract administration, SCE's duties as the CDWR's limited agent for allocated CDWR contracts, and portfolio dispatch are reviewed annually by the CPUC for reasonableness. The CPUC has currently established a maximum disallowance cap of $37 million for these activities.

In accordance with CPUC decisions, SCE, as the CDWR's limited agent, performs certain services for CDWR contracts allocated to SCE by the CPUC, including arranging for natural gas supply. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through coordination with SCE, has hedged a portion of its expected natural gas requirements for the gas tolling contracts allocated to SCE. Increases in gas prices over time, however, will increase the CDWR's gas costs. California state law permits the CDWR to recover its actual costs through rates established by the CPUC. This would affect rates charged to SCE's customers, but would not affect SCE's earnings or cash flows. As discussed under the heading, "Regulatory Matters — Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates," if the existing CDWR power contracts, which have related natural gas supply contracts, are novated or replaced and SCE becomes a party to such contracts, SCE may have additional exposure to a rise in gas prices. SCE is currently unable to predict which or how many existing CDWR contracts will be novated or replaced. However, due to the expected recovery through regulatory mechanisms these power procurement expenses are not expected to affect earnings.

Natural Gas and Electricity Price Risk

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

To mitigate SCE's exposure to spot-market prices, SCE enters into energy options, tolling arrangements, forward physical contracts and transmission congestion rights (FTRs and CRRs). SCE also enters into contracts for power and gas options, as well as swaps and futures, in order to mitigate its exposure to increases in natural gas and electricity pricing. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans.

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

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

	December 31, 2008		December 31, 2007	
In millions	Assets	Liabilities	Assets	Liabilities
Electricity options, swaps and forward arrangements	**$ 7**	**$ 15**	$ 13	$ 57
Gas options, swaps and forward arrangements	**80**	**304**	46	22
Firm transmission rights and congestion revenue rights[1]	**81**	**—**	22	—
Tolling arrangements[2]	**63**	**647**	—	—
Netting and collateral	**—**	**(72)**	—	(2)
Total	**$ 231**	**$ 894**	$ 81	$ 77

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

In September 2007 and November 2008, the CAISO allocated CRRs for the period April 2009 through December 2017 based on its expected generation flows. In addition, during the fourth quarter of 2008 SCE participated in a CAISO auction for the procurement of additional CRRs. The CRRs meet the definition of a derivative under SFAS No. 133. In accordance with SFAS No. 157, SCE recognized the CRRs at a $73 million fair value for the short term portion. SCE recorded liquidity reserves against the long-term CRRs fair values since there were no quoted long-term market prices for the CRRs and insufficient evidence of long-term market prices.

(2) In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced agreements with different project developers who have agreed to construct new, state-of-the-art Southern California generating resources. SCE has entered into a number of contracts, of which five received regulatory approval in the fourth quarter of 2008 and are recorded as financial derivatives. The contracts provide for fixed capacity payments as well as fixed pricing for energy delivered. The mark to market unrealized loss associated with the agreements are due to the decrease in forward gas market prices.

A 10% increase in electricity prices at December 31, 2008 would increase the fair value of electricity options, swaps and forward arrangements by approximately $39 million; a 10% decrease in electricity prices at December 31, 2008, would decrease the fair value by approximately $38 million. A 10% increase in electricity prices at December 31, 2008 would increase the fair value of tolling arrangements by approximately $493 million; a 10% decrease in electricity prices at December 31, 2008, would decrease the fair value by approximately $299 million. A 10% increase in gas prices at December 31, 2008 would increase the fair value of gas options, swaps and forward arrangements by approximately $101 million; a 10% decrease in gas prices at December 31, 2008, would decrease the fair value by approximately $112 million. A 10% increase in electricity prices at December 31, 2008 would decrease the fair value of firm transmission rights and congestion revenue rights by approximately $3 million; a 10% decrease in electricity prices at December 31, 2008, would decrease the fair value by approximately $3 million.

SCE's realized gains and losses arising from derivative instruments are reflected in purchased-power expense and are recovered through the ERRA mechanism. Unrealized gains and losses have no impact on purchased-power expense due to regulatory mechanisms. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. Realized losses on economic hedging were $60 million in 2008, $132 million in 2007, and $339 million in 2006. Unrealized (gains) losses on economic hedging were $638 million in 2008, $(94) million in 2007, and $237 million in 2006. Changes in realized and unrealized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007. Changes in realized and unrealized gains and losses on economic hedging activities in 2007 compared to 2006 were primarily due to changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market in 2007.

Market Redesign and Technology Upgrade

As previously discussed in "Regulatory Matters — Current Regulatory Developments — Market Redesign and Technology Upgrade," the CAISO has targeted the MRTU market to be operational on March 31, 2009, subject to certain conditions. The MRTU market design allows the CAISO to conduct a day-ahead market that combines energy, ancillary services and congestion management. By starting this process in the day-ahead time frame, there is less reliance on the more volatile hour-ahead and real-time markets.

The new MRTU market will provide day-ahead and real-time markets using Nodal Locational Marginal Prices, eliminating the current zonal environment. The impact of MRTU on SCE is primarily driven by this transition from zonal to nodal prices as well as the introduction of a central day-ahead energy market operated by CAISO. The nodal prices will provide enhanced transparency of market prices throughout the CAISO control area, but it may also make forecasting prices more challenging due to the complexity and data intensity that CAISO uses to calculate energy prices. The introduction of the day-ahead market (known as the Integrated Forward Market or IFM) will change the way SCE manages its portfolio: rather than matching supply and demand resources before submitting energy schedules to CAISO as is done today, under MRTU SCE will need to bid its generation and load requirements into the IFM. In essence, SCE will sell its generation from its utility-owned generation assets and existing power procurement contracts through IFM and buy its load requirements from IFM. SCE will bid its generation at nodes near the source of the generation, but will take delivery at nodes throughout SCE's service territory. Congestion may occur due to transmission constraints resulting in transmission congestion charges and differences in Nodal Locational Marginal Prices at the various nodes. The CAISO created a commodity, CRRs, which entitles the holder to receive (or pay) the value of transmission congestion between specific nodes, acting as an economic hedge against transmission congestion charges.

MRTU also introduces a new CAISO market called Residual Unit Commitment (RUC). This market enables CAISO to procure additional generation capacity (in addition to what cleared in the day-ahead market) to meet the CAISO-estimated load. SCE is required to participate in the RUC market with its Resource Adequacy units and may participate with other units as well.

The CAISO market that exists today for ancillary services and real-time supplemental energy will continue in MRTU, but will be adapted to the nodal pricing model and SCE will continue to participate in these markets. Due to established regulatory mechanisms SCE's fair value changes have no impact on purchased-power expense or earnings.

Credit Risk

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

To manage credit risk, SCE looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. SCE measures, monitors and mitigates credit risk to the extent possible. SCE manages the credit risk on the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. SCE's risk management committee regularly reviews and evaluates procurement credit exposure and approves credit limits for transacting with counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate. However, all of the contracts that SCE has entered into with counterparties are either entered into under SCE's short-term or long-term procurement plan which has been approved by the CPUC, or the contracts are approved by the CPUC before becoming effective. As a result of regulatory recovery mechanisms, losses from non-performance are not expected to affect earnings, but may temporarily affect cash flows. SCE anticipates future delivery of energy by counterparties, but given the current market condition, SCE cannot predict whether the counterparties will be able to continue operations and deliver energy under the contractual agreements.

The credit risk exposure from counterparties for power and gas trading activities is measured as the sum of net accounts receivable (accounts receivable less accounts payable) and the current fair value of net derivative assets reflected on the balance sheet. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE's credit risk exposure from counterparties is based on a net exposure under these arrangements. At December 31, 2008, the amount of balance sheet exposure as described above, broken down by the credit ratings of SCE's counterparties, was as follows:

	December 31, 2008		
In millions	**Exposure**[2]	**Collateral**	**Net Exposure**
S&P Credit Rating[1]			
A or higher	$ 73	$ 3	$ 70
A-	81	(1)	82
BBB+	5	—	5
BBB	—	—	—
BBB-	—	—	—
Below investment grade and not rated	—	2	(2)
Total	**$ 159**	**$ 4**	**$ 155**

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

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

The credit risk exposure set forth in the above table is comprised of $10 million of net accounts receivable and payables and $145 million representing the fair value, adjusted for counterparty credit reserves, of derivative contracts.

Due to recent developments in the financial markets, the credit ratings may not be reflective of the related credit risk. The CAISO comprises 53% of the total net exposure above and is mainly related to purchases of CRRs and FTRs (see "— Commodity Price Risk" for further information). Certain of SCE's long-term tolling agreements comprise 36% of the total net exposure.

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

The following subsections of "Results of Operations and Historical Cash Flow Analysis" provide a discussion on the changes in various line items presented on the Consolidated Statements of Income, as well as a discussion of the changes on the Consolidated Statements of Cash Flows.

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by EME. The QFs sell electricity to SCE and steam to nonrelated parties. As required by FIN 46(R), SCE consolidates these Big 4 projects.

Electric Utility Operating Revenue

The following table sets forth the major components of operating revenue:

In millions	2008	2007	2006
Operating revenue			
Retail billed and unbilled revenue	**$ 9,307**	$ 9,213	$ 9,639
Balancing account (over)/under collections	**568**	(270)	(891)
Sales for resale	**580**	489	369
Big 4 projects (SCE's VIEs)	**409**	379	385
Other (including intercompany transactions)	**384**	422	357
Total	**$ 11,248**	$ 10,233	$ 9,859

SCE's retail sales represented approximately 88%, 87% and 88% of operating revenue for the years ended December 31, 2008, 2007 and 2006, respectively. Due to warmer weather during the summer months and SCE's rate design, operating revenue during the third quarter of each year is generally higher than other quarters. Of total operating revenue, $6.7 billion, $5.3 billion, and $5.5 billion was used to collect costs subject to balancing account treatment in 2008, 2007 and 2006, respectively.

Total operating revenue increased by $1 billion in 2008 compared to 2007. The variances for the revenue components are as follows:

- Retail billed and unbilled revenue increased $94 million in 2008, compared to the same period in 2007. The increase reflects a rate increase (including impact of tiered rate structure) of $92 million and a sales volume increase of $2 million. The rate increase was due to minor variations of usage by rate class.

- SCE's revenue requirement provides recovery of pass-through costs under ratemaking mechanisms (balancing accounts) authorized by the CPUC. The revenue requirement for pass-through costs provides recovery of fuel and purchased-power expenses, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses and depreciation expense related to certain projects. SCE recognizes revenue equal to actual costs incurred for pass-through costs. In 2008, SCE accrued $568 million of revenue above the authorized revenue requirement compared to a deferral of revenue of $270 million in 2007. The 2008 accrual is due to higher purchased power and fuel costs experienced during the year compared to levels authorized in rates (see "— Purchased-Power Expense" and "— Fuel Expense" for further information).

- Sales for resale represent the sale of excess energy. Excess energy from SCE sources which may exist at certain times is resold in the energy markets. Sales for resale revenue increased for 2008 due to higher excess energy in 2008 compared to the same period in 2007, resulting from increased kWh purchases from new contracts, as well as increased sales from least cost dispatch energy. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.

Total operating revenue increased by $374 million in 2007 compared to 2006 (as shown in the table above). The variances for the revenue components are as follows:

- Retail billed and unbilled revenue decreased $426 million in 2007, compared to the same period in 2006. The decrease reflects a rate decrease (including impact of tiered rate structure) of $545 million offset by a sales volume increase of $119 million. Electric utility revenue from rate changes decreased mainly from the redesign of SCE's tiered rate structure which resulted in a decrease of residential rates in the higher tiers. Effective February 14, 2007, SCE's system average rate decreased to 13.9¢ per-kWh (including 3.0¢ per-kWh related to CDWR) mainly as the result of projected lower natural gas prices in 2007, as well as the refund of overcollections in the ERRA balancing account that occurred in 2006 from lower than expected natural gas prices and higher than expected summer 2006 sales volume (see "Regulatory Matters — Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates," and "— Energy Resource Recovery Account Proceedings" for further discussion of these rate changes). Electric utility revenue resulting from sales volume changes was mainly due to customer growth as well as an increase in customer usage.
- SCE's revenue requirement provides recovery of pass-through costs under ratemaking mechanisms (balancing accounts) authorized by the CPUC. The revenue requirement for pass-through costs provides recovery of fuel and purchased-power expenses, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses and depreciation expense related to certain projects. SCE recognizes revenue equal to actual costs incurred for pass-through costs. In 2007, SCE deferred approximately $270 million compared to a deferral of approximately $891 million in 2006. The decrease in deferred revenue was mainly due to lower purchased power and fuel costs experienced during 2007, compared to levels authorized in rates, resulting from warmer weather in 2006 (see "— Purchased-Power Expense" and "— Fuel Expense" for further information).
- Electric utility revenue from sales for resale represents the sale of excess energy. Excess energy from SCE sources which may exist at certain times is resold in the energy markets. Sales for resale revenue increased due to higher excess energy in 2007, compared to 2006. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers, CDWR bond-related costs and a portion of direct access exit fees are remitted to the CDWR and are not recognized as revenue by SCE. The amounts collected and remitted to CDWR were $2.2 billion, $2.3 billion and $2.5 billion for the years ended December 31, 2008, 2007 and 2006, respectively.

Fuel Expense

SCE's fuel expense increased $209 million in 2008 and $79 million in 2007. The 2008 increase was mainly due to an $85 million increase at SCE's Mountainview plant resulting from higher gas costs in 2008 and higher gas costs at SCE's VIEs which resulted in an increase of $104 million. The 2007 increase was mainly due to a $70 million increase at SCE's Mountainview plant due to higher generation and higher gas costs in 2007; and a $20 million increase in nuclear fuel expense in 2007 resulting from higher generation in 2007 due to a 2006 planned refueling and maintenance outage at SCE's San Onofre Units 2 and 3.

Purchased-Power Expense

In millions **For The Year Ended December 31,**	**2008**	**2007**	**2006**
Purchased-power	**$ 3,816**	$ 3,179	$ 2,940
Realized losses on economic hedging activities – net	**60**	132	339
Energy settlements and refunds	**(31)**	(76)	(180)
Total purchased-power expense	**$ 3,845**	$ 3,235	$ 3,099

SCE's total purchased-power expense increased $610 million in 2008 and $136 million in 2007.

Purchased power, in the table above, increased $637 million in 2008 and $239 million in 2007. The 2008 increase was due to: higher bilateral energy purchases of $360 million, resulting from higher costs per kWh due to higher gas prices and increased kWh purchases; higher QF purchased-power expense of $135 million, resulting from increased kWh purchases and an increase in the average spot natural gas prices for certain contracts; and higher ISO-related energy costs of $165 million. These increases were partially offset by $30 million of lower firm transmission rights costs. The 2007 increase was due to higher bilateral energy purchases of $230 million, resulting from higher costs per kWh and increased kWh purchases from new contracts entered into in 2007; higher QF purchased-power expense of $105 million, resulting from an increase in the average spot natural gas prices (as discussed further below); and higher firm transmission right costs of $50 million. The 2007 increase was partially offset by a decrease in ISO-related energy costs of $150 million.

SCE's realized gains and losses arising from derivative instruments are reflected in purchased-power expense and are recovered through the ERRA mechanism. Unrealized gains and losses have no impact on purchased-power expense due to regulatory mechanisms. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. Realized losses on economic hedging were $60 million in 2008, $132 million in 2007, and $339 million in 2006. Unrealized (gains) losses on economic hedging were $638 million in 2008, $(94) million in 2007, and $237 million in 2006. Changes in realized and unrealized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007. Changes in realized and unrealized gains and losses on economic hedging activities in 2007 compared to 2006 were primarily due to changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market in 2007. (See "Market Risk Exposures — Commodity Price Risk" for further discussion).

SCE received energy settlements and refunds (including generator settlements) of $31 million in 2008, $76 million in 2007 and $180 million in 2006. Certain of these refunds are from sellers of electricity and natural gas who manipulated the electric and natural gas markets during the energy crisis in California in 2000 – 2001 or who benefited from the manipulation by receiving inflated market prices. SCE is required to refund to customers 90% of any refunds actually realized by SCE for these types of refunds, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. Energy payments to gas-fired QFs are generally tied to spot natural gas prices. Energy payments for most renewable QFs are at a fixed price of 5.37¢ per-kWh. In late 2006, certain renewable QF contracts were amended and energy payments for these contracts are at a fixed price of 6.15¢ per-kWh, effective May 2007.

Other Operation and Maintenance Expense

SCE's other operation and maintenance expense increased $175 million in 2008 and increased $201 million in 2007. Other operating and maintenance expenses related to regulatory balancing accounts increased $70 million in 2008 compared to 2007, mainly related to higher demand-side management costs and energy efficiency costs. These accounts are recovered through regulatory mechanisms approved by the CPUC and do not impact earnings. The increase in operation and maintenance expense in 2008 also reflects: higher administrative and general costs of $35 million; higher generation expenses of $60 million related to maintenance and refueling outage expenses at San Onofre and higher overhaul and outage costs at Four Corners and Palo Verde; higher generation expenses of $20 million at Mountainview; and higher customer service costs of $15 million. The 2008 variance also reflects a decrease of approximately $30 million related to lower transmission and distribution maintenance costs. The 2007 increase reflects $98 million of higher costs associated with certain operation and maintenance expense accounts recovered through regulatory mechanisms approved by the CPUC. These costs were mainly related to both higher demand-side management and energy efficiency costs partially offset by lower must-run and must-offer obligation costs related to the reliability of the ISO systems.

The 2007 increase was also due to higher transmission and distribution maintenance costs of approximately $20 million; higher health care costs and other benefits of $30 million; higher generation expenses of $20 million at Mountainview; higher uncollectible accounts of $10 million; and higher legal costs of $20 million. The 2007 increase was partially offset by lower generation-related costs of approximately $20 million in 2007 resulting from the planned refueling and maintenance outages at SCE's San Onofre Units 2 and 3 in the first quarter of 2006.

Depreciation, Decommissioning and Amortization Expense

SCE's depreciation, decommissioning and amortization expense increased $103 million in 2008 and increased $61 million in 2007. The 2008 increase was primarily due to $90 million increased depreciation resulting from additions to transmission and distribution assets (see "Liquidity — Capital Expenditures" for a further discussion); and a $17 million cumulative depreciation rate adjustment recorded in the second quarter of 2008. The 2007 increase was primarily due to $50 million increased depreciation resulting from additions to transmission and distribution asset additions (see "Liquidity — Capital Expenditures" for a further discussion).

Property and Other Taxes

SCE's property and other taxes increased by $15 million in 2008 and $11 million in 2007. The 2008 and 2007 increases were primarily due to higher employer payroll taxes and property taxes.

Interest Income

SCE's interest income decreased $22 million in 2008 and $14 million in 2007. The 2008 and 2007 decreases were mainly due to lower undercollection balances in certain balancing accounts and lower interest rates applied to those undercollections.

Other Nonoperating Income

SCE's other nonoperating income increased $12 million in 2008. The 2008 increase was due to receipt of corporate-owned life insurance proceeds and an increase in allowance for funds used during construction – equity resulting from an increase in construction work in progress due to planned capital expenditures (see "Liquidity — Capital Expenditures" for further discussion). The increase was partially offset by payments received in the third quarter of 2007 for settlement of claims related to the natural gas purchased contracts for one of SCE's VIE projects.

Interest Expense – Net of Amounts Capitalized

SCE's interest expense – net of amounts capitalized decreased $22 million in 2008 and increased $30 million in 2007. The 2008 decrease was mainly due to lower over-collections of certain balancing accounts and lower interest rates applied to those over-collections during 2008, compared to 2007. This 2008 decrease was partially offset by higher interest expense on short-term debt and long-term debt resulting from higher balances compared to the same period in 2007. The 2007 increase was mainly due to higher interest expense on balancing account overcollections in 2007, as compared to 2006, and higher interest expense on long-term debt resulting from higher balances outstanding during 2007, as compared to 2006.

Other Nonoperating Deductions

SCE's other nonoperating deductions increased $78 million in 2008 and decreased $15 million in 2007. The 2008 increase primarily resulted from a CPUC decision in September 2008 related to SCE incentives claimed under a CPUC-approved PBR mechanism. The decision required SCE to refund $28 million and $20 million related to customer satisfaction and employee safety reporting incentives, respectively, and further required SCE to forego claimed incentives of $20 million and $15 million related to customer satisfaction and employee safety reporting, respectively. The decision also required SCE to refund $33 million for employee bonuses related to the program and imposed a statutory penalty of $30 million. During the third quarter of 2008, SCE recorded a charge of $49 million, after-tax ($60 million, pre-tax) in the consolidated statements of income related to this decision. The 2008 increase in other nonoperating deductions was also due to approximately $10 million for expenditures related to civic, political and related activities, and donations. The 2007 decrease was mainly due to a penalty accrual of $23 million under the customer satisfaction performance mechanism discussed above which was recognized in 2006.

Income Taxes

The composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for all periods presented. The lower effective tax rate of 31.8% realized in 2008 as compared to the statutory rate was primarily due to software and property related flow through deductions. The lower effective tax rate of 30.8% realized in 2007 as compared to the statutory rate was primarily due to reductions made to the income tax reserve to reflect progress made in an administrative appeals process with the IRS related to the income tax treatment of certain costs associated with environmental remediation and to reflect an audit settlement of state tax issues. The lower effective tax rate of 34.6% realized in 2006 as compared to the statutory rate was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue partially offset by tax reserve accruals.

Historical Cash Flow Analysis

The "Historical Cash Flow Analysis" section of this MD&A discusses consolidated cash flows from operating, financing and investing activities.

Cash Flows from Operating Activities

Cash provided by operating activities was $1.6 billion in 2008, $3.0 billion in 2007 and $2.6 billion in 2006. The 2008 change was mainly due to a net $300 million increase in balancing account undercollections, mainly related to a $750 million increase in ERRA undercollections, partially offset by $200 million in refund payments received related to SCE's public purpose programs, $100 million refunded to ratepayers as a result of SCE's PBR decision, and a net $150 million in other balancing account overcollections. The change was also due to a $240 million decrease related to the elimination of amounts collected in 2008 for the repayment of SCE rate reduction bonds. These bonds were fully repaid in December 2007. The bond payment is reflected in financing activities. The 2008 change was also due to the timing of cash receipts and disbursements related to working capital items.

The 2007 change was due to the timing of cash receipts and disbursements related to working capital items including lower income taxes paid in 2007, compared to 2006. The 2007 change also reflects a decrease in revenue collected from SCE's customers primarily due to lower rates in 2007, compared to 2006. On February 14, 2007, SCE reduced its system average rate mainly as the result of estimated lower natural gas prices in 2007, the refund of overcollections in the ERRA balancing account that occurred in 2006 and the impact of the redesign of SCE's tiered rate structure in 2007.

Cash Flows from Financing Activities

Net cash provided (used) by financing activities from continuing operations mainly consisted of long-term debt and short-term debt issuances (payments).

Financing activities in 2008 were as follows:

- In January, SCE 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.

- During the first quarter, SCE 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.
- In January, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. SCE retired this preferred stock in January 2008 and recorded a $2 million gain on the cancellation of reacquired capital stock (reflected in the caption "Common stock" on the consolidated balance sheets).
- In August, SCE issued $400 million of 5.50% first and refunding mortgage bonds due in 2018. The proceeds were used to repay SCE's outstanding commercial paper of approximately $110 million and borrowings under the credit facility of $200 million, as well as for general corporate purposes.
- In October, SCE issued $500 million of 5.75% first and refunding mortgage bonds due in 2014. The proceeds were used for general corporate purposes.
- During 2008, SCE's net issuances of short-term debt were $1.4 billion.
- Other financing activities in 2008 include dividend payments of $325 million paid to Edison International and payments of $36 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Financing activities in 2007 were as follows:

- During 2007, SCE's net issuance of short-term debt was $500 million.
- During the fourth quarter of 2007, SCE repaid the remaining outstanding balance of its rate reduction bonds in the amount of $246 million.
- Other financing activities in 2007 include dividend payments of $135 million paid to Edison International and payments of $135 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Financing activities in 2006 included activities related to the rebalancing of SCE's capital structure and rate base growth, as follows:

- In January 2006, SCE issued $500 million of first and refunding mortgage bonds which consisted of $350 million of 5.625% bonds due in 2036 and $150 million of floating rate bonds due in 2009. The proceeds from this issuance were used in part to redeem $150 million of variable rate first and refunding mortgage bonds due in January 2006 and $200 million of its 6.375% first and refunding mortgage bonds due in January 2006.
- In January 2006, SCE issued 2,000,000 shares of 6% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of approximately $197 million.
- In April 2006, SCE issued $331 million of tax-exempt bonds which consisted of $196 million of 4.10% bonds which are subject to remarketing in April 2013 and $135 million of 4.25% bonds which are subject to remarketing in November 2016. The proceeds from this issuance were used to call and redeem $196 million of tax-exempt bonds due February 2008 and $135 million of tax-exempt bonds due March 2008. This transaction was treated as a noncash financing activity.
- In December 2006, SCE issued $400 million of 5.55% first and refunding mortgage bonds due in 2037. The proceeds from this issuance were used for general corporate purposes.
- Other financing activities in 2006 include dividend payments of $251 million paid to Edison International and payments of $107 million for the purchase and delivery of outstanding common stock for settlement of stock based awards (facilitated by a third party).

Cash Flows from Investing Activities

Net cash used by investing activities was $2.3 million in 2008, $2.4 million in 2007, and $2.3 million in 2006.

Cash flows from investing activities are affected by capital expenditures and SCE's funding of nuclear decommissioning trusts.

Investing activities in 2008 reflect $2.3 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $99 million for nuclear fuel acquisitions. Investing activities also include net purchases of nuclear decommissioning trust investments and other of $7 million.

Investing activities in 2007 reflect $2.3 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $123 million for nuclear fuel acquisitions. Investing activities also include net purchases of nuclear decommissioning trust investments and other of $133 million.

Investing activities in 2006 reflect $2.2 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $81 million for nuclear fuel acquisitions and $13 million related to the Mountainview plant. Investing activities also include net purchases of nuclear decommissioning trust investments and other of $140 million.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

The accounting policies described below are viewed by management as critical because their application is the most relevant and material to SCE's results of operations and financial position and these policies require the use of material judgments and estimates.

Rate Regulated Enterprises

SCE applies SFAS No. 71 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 its net investment, or rate base. Regulators also may impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for probable future costs collected through rates in advance. SCE's management continually assesses whether the 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 incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. 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, 2008, the consolidated balance sheets included regulatory assets of $6.0 billion and regulatory liabilities of $3.6 billion. Management continually evaluates the anticipated recovery of regulatory assets, incentives and revenue subject to refund, as well as the anticipated cost of regulatory liabilities or penalties and provides for allowances and/or reserves as appropriate.

Derivative Financial Instruments and Hedging Activities

SCE follows SFAS No. 133 which requires derivative financial instruments to be recorded at their fair value unless an exception applies. SFAS No. 133 also requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for hedge accounting, depending on the nature of the hedge, changes in fair value are either offset by changes in the fair value of the hedged assets, liabilities or firm commitments through earnings, or recognized in other comprehensive income until the hedged item is recognized in earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings. SCE fair value changes are expected to be recovered from or refunded to ratepayers, and therefore SCE's fair value changes have no impact on earnings, but may temporarily affect cash flows.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when SCE has the legal right of offset, such as multiple contracts executed with the same counterparty under master netting arrangements. The results of derivative activities are recorded as part of cash flows from operating activities in the consolidated statements of cash flows. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment.

Determining whether or not SCE's transactions meet the definition of a derivative instrument requires management to exercise significant judgment, including determining whether the transaction has one or more underlyings, one or more notional amounts, requires no initial net investment, and whether the terms require or permit net settlement. If it is determined that the transaction meets the definition of a derivative instrument, additional management judgment is exercised in determining whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment, if elected.

Most of SCE's QF contracts are not required to be recorded on its balance sheet because they either do not meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception under accounting rules is recorded on the balance sheet at fair value, based on financial models. Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases under EITF No. 01-8.

For those transactions that are accounted for as derivative instruments, determining the fair value requires management to exercise significant judgment. SCE makes estimates and assumptions concerning future commodity prices, load requirements and interest rates in determining the fair value of a derivative instrument. The fair value of a derivative is susceptible to significant change resulting from a number of factors, including volatility of commodity prices, credit risks, market liquidity and discount rates.

Fair Value Accounting

SCE follows SFAS No. 157 which established a framework for measuring fair value. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date (referred to as an "exit price" in SFAS No. 157). Edison International's assets and liabilities carried at fair value primarily consist of derivative contracts, nuclear decommissioning trust investments, pension and postretirement benefits other than pension, and money market funds. Derivative contracts primarily relate to power and gas and include contracts for forward physical sales and purchases, options and forward price swaps which settle only on a financial basis (including futures contracts). Derivative contracts can be exchange traded, over-the-counter traded, or structured transactions.

SCE makes estimates and significant judgments in order to determine the fair value of an instrument including those related to quoted market prices, time value of money, volatility of the underlying commodities, non-performance risks of counterparties and other factors. If quoted market prices are not available, SCE uses internally maintained standardized or industry accepted models to determine the fair value. The models are updated with spot prices, forward prices, volatilities and interest rates from regularly published and widely distributed independent sources. Under SFAS No. 157, when actual market prices, or relevant observable inputs are not available it is appropriate to use unobservable inputs which reflect management assumptions, including extrapolating limited short-term observable data and developing correlations between liquid and non-liquid trading hubs.

In addition, SFAS No. 157 established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). See "Southern California Edison Company Notes to Consolidated Financial Statements — Note 10. Fair Value Measurements" for further information.

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

Level 3 also includes derivatives that trade infrequently (such as FTRs and CRRs in the California market and over-the-counter derivatives at illiquid locations), and long-term power agreements. For illiquid FTRs, SCE reviews objective criteria related to system congestion and other underlying drivers and adjusts fair value when SCE concludes a change in objective criteria would result in a new valuation that better reflects the fair value. Recent auction prices are used to determine the fair value of short-term CRRs and the proprietary model is used for long-term CRRs. SCE recorded liquidity reserves against the long-term CRRs fair values since there were no quoted long-term market prices for the CRRs and insufficient evidence of long-term market prices.

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

The amount of SCE's Level 3 derivative assets and liabilities measured using significant unobservable inputs as a percentage of the total derivative assets and total derivative liabilities (excluding netting and collateral) measured at fair value were 98% and 77%, respectively.

SCE's investment policies and CPUC requirements place limitations on the types and investment grade ratings of the securities that may be held by the nuclear decommissioning trust funds. These policies restrict the trust funds from holding alternative investments and limit the trust funds' exposures to investments in highly illiquid markets. With respect to equity securities, the trustee obtains prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which SCE is able to independently corroborate. Regarding fixed income securities, the trustee receives multiple prices from pricing services, which enable cross-provider validations by the trustee in addition to unusual daily movement checks. A primary price source is identified based on asset type, class or issue for each security. The trustee monitors prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the trustee challenges an assigned price and determines that another price source is considered to be preferable. Additionally, SCE corroborates the fair values of securities by comparison to other market-based price sources obtained by SCE's investment managers. The trustee validation procedures for pension and PBOP assets are the same as the nuclear decommissioning trusts. Level 3 includes prices or valuations that require inputs that are both significant to the fair value measurements and unobservable.

Management uses significant judgment and assumptions in order to determine the fair value of Level 3 transactions. Due to its regulatory treatment, SCE's fair value transactions discussed above are recovered in rates.

Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under 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 applies the asset and liability method of accounting for deferred income taxes as required by SFAS No. 109, "Accounting for Income Taxes." In accordance with FIN 48, "Accounting for Uncertainty in Income Taxes," SCE applies judgment to assess each tax position taken on filed tax returns and tax positions expected to be taken on future returns to determine whether a tax position is more likely than not to be sustained and recognized in the financial statements. However, all temporary tax positions, whether or not the more likely than not threshold of FIN 48 is met, are recorded in the financial statements in accordance with the measurement principles of FIN 48.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each jurisdiction in which it operates. This process involves estimating actual current 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 tax laws. The application of these positions is subject to interpretation and audit by the IRS.

Investment tax credits associated with rate-regulated public utility property are deferred and amortized over the lives of the properties.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as appropriate, reflected in the captions "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income.

Asset Impairment

SCE evaluates long-lived assets based on a review of estimated cash flows expected to be generated whenever events or changes in circumstances indicate the carrying amount of such investments or assets may not be recoverable. If the carrying amount of the investment or asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, then an impairment loss for long-lived assets is recognized in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." In accordance with SFAS No. 71, SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from the ratepayers.

The assessment of impairment is a critical accounting estimate because significant management judgment is required to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors that SCE considers important, which could trigger an impairment, include operating losses from a project, projected future operating losses, the financial condition of counterparties, or significant negative industry or economic trends.

Nuclear Decommissioning

Edison International's legal AROs related to the decommissioning of SCE's nuclear power facilities are recorded at fair value. The fair value of decommissioning SCE's nuclear power facilities is based on site-specific studies performed in 2005 for SCE's San Onofre and Palo Verde nuclear facilities. Changes in the estimated costs or timing of decommissioning, or the assumptions underlying these estimates are based on management judgments and could cause material revisions to the estimated total cost to decommission these facilities. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. As of December 31, 2008, the decommissioning trust balance was $2.5 billion. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The next filing is in April 2009 for contribution changes in 2011. The contributions are determined based on an analysis of the current value of trust assets and long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates. Trust funds are recorded on the balance sheet at fair market value.

SCE's nuclear decommissioning trusts are accounted for in accordance with SFAS No. 115 and due to regulatory recovery of SCE's nuclear decommissioning expense, rate-making accounting treatment is applied to all nuclear decommissioning trust activities in accordance with SFAS No. 71. As a result, nuclear decommissioning activities do not affect SCE's earnings.

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

Decommissioning of San Onofre Unit 1 is underway. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds, subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 of $59 million as of December 31, 2008 is recorded as an ARO liability.

Pensions and Postretirement Benefits Other than Pensions

SFAS No. 158 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). SCE adopted SFAS No. 158 as of December 31, 2006. In accordance with SFAS No. 71, SCE recorded regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends. SCE already has a fiscal year-end measurement date for all of its postretirement plans.

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.

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. At the December 31, 2008 measurement date, SCE used a discount rate of 6.25% for both pensions and PBOPs.

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. The expected rate of return on plan assets was 7.5% for pensions and 7.0% for PBOP. 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 (losses) on the pension plan assets were (31.0)%, 1.5% and 4.1% for the one-year, five-year and ten-year periods ended December 31, 2008, respectively. Actual time-weighted, annualized returns (losses) on the PBOP plan assets were (31.1)%, (0.2)%, and 1.0% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense calculated in accordance with SFAS No. 87, "Employers' Accounting for Pensions," and SFAS No. 158 is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2008, this cumulative difference amounted to a regulatory liability of $71 million, meaning that the rate-making method has recognized $71 million more in expense than the accounting method since implementation of SFAS No. 87 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 nonutility PBOP plans have no plan assets.

At December 31, 2008, SCE's PBOP plans had a $2.2 billion benefit obligation. Total expense for these plans was $39 million for 2008. The health care cost trend rate is 9.25% for 2008, gradually declining to 5.0% for 2015 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2008 by $247 million and annual aggregate service and interest costs by $17 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2008 by $222 million and annual aggregate service and interest costs by $15 million.

Accounting for Contingencies

In accordance with SFAS No. 5, "Accounting for Contingencies," 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. These reserves are based on management judgment and estimates taking into consideration available information and are adjusted when events or circumstances cause these judgments or estimates to change. Edison International provides disclosure for contingencies when there is a reasonable possibility that a loss or an additional loss may be incurred. Gain contingencies are recognized in the financial statements when they are realized. Actual amounts realized upon settlement of contingencies may be different than amounts recorded and disclosed and could have a significant impact on the liabilities, revenue and expenses recorded in the financial statements. See "Regulatory Matters" and "Other Developments" for a discussion of contingencies and regulatory issues.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements are discussed in Note 1 — Summary of Significant Accounting Policies — New Accounting Pronouncements under "Southern California Edison Company's Notes to Consolidated Financial Statements."

COMMITMENTS AND INDEMNITIES

SCE's commitments as of December 31, 2008, for the years 2009 through 2013 and thereafter are estimated below:

In millions	2009	2010	2011	2012	2013	Thereafter
Long-term debt maturities and interest[1]	$ 489	$ 570	$ 320	$ 320	$ 319	$ 10,654
Fuel supply contract payments	207	117	158	198	192	725
Purchased-power capacity payments	289	368	519	681	660	4,308
Operating lease obligations	689	673	500	390	378	2,093
Capital lease obligations	4	12	17	19	19	1,153
Other commitments	7	7	7	7	8	24
Employee benefit plans contributions[2]	164	—	—	—	—	—
Total[3]	**$ 1,849**	**$ 1,747**	**$ 1,521**	**$ 1,615**	**$ 1,576**	**$ 18,957**

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2008 and related forecast interest payments over the applicable period of the debt.

(2) Amount includes estimated contributions to the pension and PBOP plans. The estimated contributions for SCE are not available beyond 2009.

(3) At December 31, 2008, SCE had a total net liability recorded for uncertain tax positions of $324 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.

Fuel Supply Contracts

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.

Power-Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table above). There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into power-purchase settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the consolidated balance sheets.

Operating and Capital Leases

In accordance with EITF No. 01-8, power contracts signed or modified after June 30, 2003, need to be assessed for lease accounting requirements. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. As of December 31, 2005, SCE had six power contracts classified as operating leases. In 2006, SCE modified 62 power contracts. No contracts were modified in 2007 and 2008. The modifications to the contracts resulted in a change to the contractual terms of the contracts at which time SCE reassessed these power contracts under EITF No. 01-8 and determined that the contracts are leases and subsequently met the requirements for operating leases under SFAS No. 13. These power contracts had previously been grandfathered relative to EITF No. 01-8 and did not meet the normal purchases and sales exception. As a result, these contracts were recorded on the consolidated balance sheets at fair value in accordance with SFAS No. 133. Due to regulatory mechanisms, fair value changes did not affect earnings. At the time of modification, SCE had assets and liabilities related to mark-to-market gains or losses. Under SFAS No. 133, the assets and liabilities were reclassified to a lease prepayment or accrual and were included in the cost basis of the lease. The lease prepayment and accruals are being amortized over the life of the lease on a straight-line basis. At December 31, 2008, the net liability was $64 million. At December 31, 2008, SCE had 69 power contracts classified as operating leases. Operating lease expense for power purchases was $328 million in 2008, $297 million in 2007, and $188 million in 2006. In addition, as of December 31, 2008, SCE had four power purchase contracts which met the requirements for capital leases. These capital leases have a net commitment of $1.22 billion at December 31, 2008 and $20 million at December 31, 2007. The total estimated capital lease executory costs and interest expense were $1.71 billion at December 31, 2008 and $20 million at December 31, 2007.

SCE has other operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates).

Other Commitments

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $60 million through 2016 (approximately $7 million per year).

Indemnities

Indemnity Provided as Part of the Acquisition of Mountainview

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

Mountainview Filter Cake Indemnity

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

Other 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.

Management's Responsibility for Financial Reporting

The management of SCE is responsible for the integrity and objectivity of the accompanying financial statements and related information. The statements have been prepared in accordance with accounting principles generally accepted in the United States of America and are based, in part, on management estimates and judgment. Management believes that the financial statements fairly reflect SCE's financial position and results of operations.

As a further measure to assure the ongoing objectivity and integrity of financial information, the Audit Committee of the Board of Directors, which is composed of independent directors, meets periodically, both jointly and separately, with management, the independent auditors and internal auditors, who have unrestricted access to the Committee. The Committee annually appoints a firm of independent auditors to conduct an audit of SCE's financial statements; reviews accounting, auditing and financial reporting issues; and is advised of management's actions regarding financial reporting matters.

SCE and its subsidiaries maintain high standards in selecting, training and developing personnel to assure that its operations are conducted in conformity with applicable laws and are committed to maintaining the highest standards of personal and corporate conduct. Management maintains programs to encourage and assess compliance with these standards.

SCE's independent registered public accounting firm, PricewaterhouseCoopers LLP, are engaged to audit the financial statements included in this Annual Report in accordance with the standards of the Public Company Accounting Oversight Board (United States) which is included in this Annual Report on the following page.

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). Under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, SCE's management conducted an evaluation of the effectiveness of 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 internal control over financial reporting was effective as of December 31, 2008.

Disclosure Controls and Procedures

The certifications of the Chief Executive Officer and Chief Financial Officer that are required by Section 302 of the Sarbanes-Oxley Act of 2002 are included as exhibits to SCE's annual report on Form 10-K. In addition, in 2008, SCE's Chief Executive Officer provided to the New York Stock Exchange (NYSE) the Annual CEO Certification regarding SCE's compliance with the NYSE's corporate governance standards.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in common shareholder's equity present fairly, in all material respects, the financial position of Southern California Edison Company (the "Company") and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 1, 4, 5 and 10 to the consolidated financial statements, the Company changed the manner in which it accounts for stock-based compensation as of January 1, 2006, defined benefit pension and other post retirement plans as of December 31, 2006, uncertain tax positions as of January 1, 2007, and margin and cash collateral deposits related to derivative positions and fair value measurement and disclosure accounting principles as of January 1, 2008.

PricewaterhouseCoopers LLP

Los Angeles, California
March 2, 2009

Consolidated Statements of Income — Southern California Edison Company

In millions — Year ended December 31,	2008	2007	2006
Operating revenue	**$ 11,248**	$ 10,233	$ 9,859
Fuel	**1,400**	1,191	1,112
Purchased power	**3,845**	3,235	3,099
Other operation and maintenance	**3,013**	2,838	2,637
Depreciation, decommissioning and amortization	**1,114**	1,011	950
Property and other taxes	**232**	217	206
Gain on sale of assets	**(9)**	—	(1)
Total operating expenses	**9,595**	8,492	8,003
Operating income	**1,653**	1,741	1,856
Interest income	**22**	44	58
Other nonoperating income	**101**	89	85
Interest expense – net of amounts capitalized	**(407)**	(429)	(399)
Other nonoperating deductions	**(123)**	(45)	(60)
Income before tax and minority interest	**1,246**	1,400	1,540
Income tax expense	**342**	337	438
Minority interest	**170**	305	275
Net income	**734**	758	827
Dividends on preferred and preference stock not subject to mandatory redemption	**51**	51	51
Net income available for common stock	**$ 683**	$ 707	$ 776

Consolidated Statements of Comprehensive Income

In millions — Year ended December 31,	2008	2007	2006
Net income	**$ 734**	$ 758	$ 827
Other comprehensive income (loss), net of tax:			
Termination and amortization of cash flow hedges – net of income tax expense of $3 for 2006	**—**	—	5
Pension and postretirement benefits other than pensions:			
Net gain (loss) arising during period – net of income tax expense (benefit) of $2 and $(2) for 2008 and 2007	**2**	(3)	—
Amortization of net gain (loss) included in expense – net of income tax expense (benefit) of $(1) and $1 for 2008 and 2007	**(2)**	2	—
Prior service cost arising during period – net	**1**	—	—
Minimum pension liability adjustment – net of income tax expense of $5 for 2006	**—**	—	7
Comprehensive income	**$ 735**	$ 757	$ 839

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

Consolidated Balance Sheets	**Southern California Edison Company**	
In millions **December 31,**	**2008**	**2007**
ASSETS		
Cash and equivalents	**$ 1,611**	$ 252
Short-term investments	**3**	—
Receivables, less allowances of $39 and $34 for uncollectible accounts at respective dates	**703**	725
Accrued unbilled revenue	**328**	370
Inventory	**365**	283
Derivative assets	**157**	53
Margin and collateral deposits	**17**	35
Regulatory assets	**605**	197
Accumulated deferred income taxes – net	**147**	146
Other current assets	**266**	188
Total current assets	**4,202**	2,249
Nonutility property – less accumulated provision for depreciation of $765 and $701 at respective dates	**953**	1,000
Nuclear decommissioning trusts	**2,524**	3,378
Other investments	**68**	69
Total investments and other assets	**3,545**	4,447
Utility plant, at original cost:		
Transmission and distribution	**20,006**	18,940
Generation	**1,819**	1,767
Accumulated provision for depreciation	**(5,570)**	(5,174)
Construction work in progress	**2,454**	1,693
Nuclear fuel, at amortized cost	**260**	177
Total utility plant	**18,969**	17,403
Derivative assets	**74**	28
Regulatory assets	**5,414**	2,721
Other long-term assets	**364**	629
Total long-term assets	**5,852**	3,378
Total assets	**$ 32,568**	$ 27,477

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

Consolidated Balance Sheets		**Southern California Edison Company**
In millions, except share amounts **December 31,**	**2008**	**2007**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**$ 1,893**	$ 500
Long-term debt due within one year	**150**	—
Accounts payable	**948**	914
Accrued taxes	**340**	42
Accrued interest	**153**	126
Counterparty collateral	**8**	42
Customer deposits	**227**	218
Book overdrafts	**224**	204
Derivative liabilities	**156**	97
Regulatory liabilities	**1,111**	1,019
Other current liabilities	**564**	548
Total current liabilities	**5,774**	3,710
Long-term debt	**6,212**	5,081
Accumulated deferred income taxes – net	**2,918**	2,556
Accumulated deferred investment tax credits	**101**	105
Customer advances	**137**	155
Derivative liabilities	**738**	13
Accumulated provision for pensions and benefits	**2,485**	786
Asset retirement obligations	**3,007**	2,877
Regulatory liabilities	**2,481**	3,433
Other deferred credits and other long-term liabilities	**902**	1,158
Total deferred credits and other liabilities	**12,769**	11,083
Total liabilities	**24,755**	19,874
Commitments and contingencies (Note 6)		
Minority interest	**380**	446
Common stock, no par value (434,888,104 shares outstanding at each date)	**2,168**	2,168
Additional paid-in capital	**532**	507
Accumulated other comprehensive loss	**(14)**	(15)
Retained earnings	**3,827**	3,568
Total common shareholder's equity	**6,513**	6,228
Preferred and preference stock not subject to mandatory redemption	**920**	929
Total shareholders' equity	**7,433**	7,157
Total liabilities and shareholders' equity	**$ 32,568**	$ 27,477

Authorized common stock is 560 million shares at each reporting period.

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

Consolidated Statements of Cash Flows — Southern California Edison Company

In millions — Year ended December 31,	2008	2007	2006
Cash flows from operating activities:			
Net income	**$ 734**	$ 758	$ 827
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**1,114**	1,011	950
Net earnings in nuclear ARO regulatory assets and liabilities	**(10)**	143	130
Other amortization	**97**	95	79
Stock-based compensation	**18**	18	27
Minority interest	**170**	305	275
Deferred income taxes and investment tax credits	**131**	(111)	(358)
Regulatory assets	**(2,725)**	503	74
Regulatory liabilities	**(221)**	176	336
Derivative assets	**(150)**	(19)	218
Derivative liabilities	**784**	(68)	(43)
Other assets	**275**	(156)	(119)
Other liabilities	**1,343**	195	325
Margin and collateral deposits – net of collateral received	**(16)**	6	(5)
Receivables and accrued unbilled revenue	**56**	147	51
Inventory and other current assets	**(151)**	(185)	(7)
Book overdrafts	**20**	64	—
Accrued interest and taxes	**325**	74	(41)
Accounts payable and other current liabilities	**(172)**	17	(138)
Net cash provided by operating activities	**1,622**	2,973	2,581
Cash flows from financing activities:			
Long-term debt issued	**1,500**	—	900
Long-term debt issuance costs	**(20)**	(1)	(24)
Long-term debt repaid	**(3)**	(207)	(352)
Bonds repurchased	**(212)**	(37)	—
Preference stock issued	**—**	—	196
Preferred stock redeemed	**(7)**	—	—
Rate reduction notes repaid	**—**	(246)	(246)
Short-term debt financing – net	**1,393**	500	—
Book overdrafts	**—**	—	(118)
Shares purchased for stock-based compensation	**(36)**	(135)	(107)
Proceeds from stock option exercises	**17**	56	45
Excess tax benefits related to stock-based awards	**4**	28	17
Minority interest	**(236)**	(210)	(322)
Dividends paid	**(376)**	(186)	(300)
Net cash provided (used) by financing activities	**2,024**	(438)	(311)
Cash flows from investing activities:			
Capital expenditures	**(2,267)**	(2,286)	(2,226)
Proceeds from nuclear decommissioning trust sales	**3,130**	3,697	3,010
Purchases of nuclear decommissioning trust investments and other	**(3,137)**	(3,830)	(3,150)
Sales of short-term investments	**—**	7,069	6,446
Purchases of short-term investments	**(3)**	(7,069)	(6,418)
Restricted cash	**—**	56	1
Customer advances for construction and other investments	**(10)**	(3)	7
Net cash used by investing activities	**(2,287)**	(2,366)	(2,330)
Net increase (decrease) in cash and equivalents	**1,359**	169	(60)
Cash and equivalents, beginning of year	**252**	83	143
Cash and equivalents, end of year	**$ 1,611**	$ 252	$ 83

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

Consolidated Statements of Changes in Common Shareholder's Equity

Southern California Edison Company

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 2005	$ 2,168	$ 361	$ (16)	$ 2,417	$ 4,930
Net income				827	827
Other comprehensive income			12		12
SFAS No. 158 – Pension and other postretirement benefits			(17)		(17)
Tax effect			7		7
Dividends declared on common stock				(240)	(240)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(51)	(51)
Shares purchased for stock-based compensation		(15)		(88)	(103)
Proceeds from stock option exercises				45	45
Noncash stock-based compensation and other		23			23
Excess tax benefits related to stock-based awards		17			17
Capital stock expense and other		(3)			(3)
Balance at December 31, 2006	$ 2,168	$ 383	$ (14)	$ 2,910	$ 5,447
Net income				758	758
FIN 48 adoption				213	213
Other comprehensive loss			(1)		(1)
Dividends declared on common stock				(100)	(100)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(51)	(51)
Shares purchased for stock-based compensation				(135)	(135)
Proceeds from stock option exercises				56	56
Noncash stock-based compensation and other		18		(5)	13
Excess tax benefits related to stock-based awards		28			28
Change in classification of shares purchased to settle performance shares		78		(78)	—
Balance at December 31, 2007	$ 2,168	$ 507	$ (15)	$ 3,568	$ 6,228
Net income				734	734
Other comprehensive income			1		1
Dividends declared on common stock				(400)	(400)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(51)	(51)
Gain on reacquired preferred stock		2			2
Shares purchased for stock-based compensation				(36)	(36)
Proceeds from stock option exercises				17	17
Noncash stock-based compensation and other		19		(5)	14
Excess tax benefits related to stock-based awards		4			4
Balance at December 31, 2008	**$ 2,168**	**$ 532**	**$ (14)**	**$ 3,827**	**$ 6,513**

Authorized common stock is 560 million shares. The outstanding common stock is 434,888,104 shares for all years reported.

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

Notes to Consolidated Financial Statements

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

Note 1. Summary of Significant Accounting Policies

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

Basis of Presentation

The consolidated financial statements include SCE, its subsidiaries and VIEs for which SCE is the primary beneficiary. Effective March 31, 2004, SCE began consolidating four cogeneration projects from which SCE typically purchases 100% of the energy produced under long-term power-purchase agreements, in accordance with FIN 46(R). Intercompany transactions have been eliminated.

SCE's accounting policies conform to accounting principles generally accepted in the United States of America, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC. SCE applies SFAS No. 71 to the portion of its operations in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of operating revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; and conversely these principles require creation of a regulatory liability for probable future costs collected through rates in advance of the actual costs being incurred. SCE's management continually evaluates the anticipated recovery of regulatory assets, liabilities, and operating revenue subject to refund and provides for allowances and/or reserves as appropriate.

Certain prior-year reclassifications have been made to conform to the December 31, 2008 consolidated financial statement presentation mostly pertaining to the adoption of FIN 39-1 and the elimination of the previously reported income statement caption "Provision for regulatory adjustment clauses – net" through classifications within relevant captions including "Operating revenue," "Purchased power," "Other operation and maintenance" and "Depreciation, decommissioning and amortization."

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

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

Book Overdrafts

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

Cash and Equivalents

Cash equivalents included money market funds totaling $1.5 billion and $83 million at December 31 2008 and 2007, respectively. The carrying value of cash equivalents approximates fair value due to maturities of less than three months. Additionally, cash and equivalents of $89 million and $110 million at December 31, 2008 and 2007, respectively are included for four projects that SCE is consolidating under an accounting interpretation for VIEs. For further discussion of money market funds, see Note 10.

Deferred Financing Costs

Debt premium, discount and issuance expenses are deferred and amortized on a straight-line basis through interest expense over the life of each related issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. SCE had unamortized loss on reacquired debt of $309 million at December 31, 2008 and $331 million at December 31, 2007 reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. SCE had unamortized debt issuance costs of $49 million at December 31, 2008 and $40 million at December 31, 2007 reflected in "Other long-term assets" on the consolidated balance sheets.

Derivative Instruments and Hedging Activities

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

SCE records its derivative instruments on its consolidated balance sheets at fair value as either assets or liabilities unless they meet the definition of a normal purchase or sale. 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. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met which requires SCE to formally document, designate, and assess the effectiveness of hedge transactions. For those derivative transactions that qualify for and for which SCE has elected hedge accounting, gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of a designated fair value hedge. For a designated hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income (loss)," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when SCE has the legal right of offset, such as multiple contracts executed with the same counterparty under master netting arrangements. In addition, derivative positions are offset against margin and cash collateral deposits in accordance with FIN No. 39-1 as discussed below in "Margin and Collateral Deposits" and "New Accounting Pronouncements." The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows.

To mitigate SCE's exposure to spot-market prices, the CPUC has authorized SCE to enter into power purchase contracts (including QFs), energy options, tolling arrangements and forward physical contracts. SCE records these derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale (as discussed above), or are classified as VIEs or leases. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes are expected to be recovered from or refunded to customers through regulatory mechanisms and therefore SCE's fair value changes have no impact on purchased-power expense or earnings. As a result, fair value changes do not affect SCE's earnings. SCE has elected not to use hedge accounting for these transactions due to this regulatory accounting treatment.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception is recorded on the consolidated balance sheets at fair value. Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases under EITF No. 01-8.

SCE enters into interest-rate locks to mitigate interest rate risk associated with future financings. SCE expects to recover any fair value changes associated with the interest-rate lock through regulatory mechanisms. Realized and unrealized gains and losses do not affect current earnings. Realized gains/losses are amortized and recovered through interest expense over the life of the new debt.

See further information about SCE's derivative instruments in Note 2 and 10.

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 authorized level on a 13-month weighted average basis of 48%. At December 31, 2008, SCE's 13-month weighted-average common equity component of total capitalization was 50.6% resulting in the capacity to pay $345 million in additional dividends.

Impairment of Long-Lived Assets

SCE evaluates the impairment of its long-lived assets based on a review of estimated cash flows expected to be generated whenever events or changes in circumstances indicate the carrying amount of such investments or assets may not be recoverable. If the carrying amount of the asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, then an impairment loss is recognized in accordance with SFAS No. 144. In accordance with SFAS No. 71, SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from the ratepayers.

Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under 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 applies the asset and liability method of accounting for deferred income taxes as required by SFAS No. 109, "Accounting for Income Taxes." In accordance with FIN 48, "Accounting for Uncertainty in Income Taxes," SCE applies judgment to assess each tax position taken on filed tax returns and tax positions expected to be taken on future returns to determine whether a tax position is more likely than not to be sustained and recognized in the financial statements. However, all temporary tax positions, whether or not the more likely than not threshold of FIN 48 is met, are recorded in the financial statements in accordance with the measurement principles of FIN 48.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each jurisdiction in which it operates. This process involves estimating actual current 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 tax laws. The application of these positions is subject to interpretation and audit by the IRS.

Investment tax credits associated with rate-regulated public utility property are deferred and amortized over the lives of the properties.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. Management uses judgment in determining whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as appropriate, reflected in the captions "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income.

For a further discussion of income taxes, see Note 4.

Inventory

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

Leases

Rent expense under operating leases for vehicle, office space and other equipment is levelized over the terms of the leases.

Capital leases are reported as long-term obligations on the consolidated balance sheets under the caption "Other deferred credits and other long-term liabilities." In accordance with SFAS No. 71, SCE's capital lease amortization expense and interest expense are reflected in the caption "Purchased power" on the consolidated statements of income.

See "Lease Commitments" in Note 6 for additional information on operating and capital lease transactions.

Margin and Collateral Deposits

Margin and collateral deposits include margin requirements and cash deposited with and received from counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the related positions. See "New Accounting Pronouncements" below for a discussion of the adoption of FIN No. 39-1. In accordance with FIN No. 39-1, SCE presents a portion of its margin and cash collateral deposits net with its derivative positions on its consolidated balance sheets. Amounts recognized for cash collateral provided to others that have been offset against net derivative liabilities totaled $72 million and $2 million at December 31, 2008 and 2007, respectively.

New Accounting Pronouncements

Accounting Pronouncements Adopted

In April 2007, the FASB issued FIN No. 39-1. This pronouncement permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. In addition, upon the adoption, companies were permitted to change their accounting policy to offset or not offset fair value amounts recognized for derivative instruments under master netting agreements. SCE adopted FIN No. 39-1 effective January 1, 2008. The adoption resulted in netting a portion of margin and cash collateral deposits with derivative positions on SCE's consolidated balance sheets, but had no impact on its consolidated statements of income. The consolidated balance sheet at December 31, 2007 has been retroactively restated for the change, which resulted in a decrease in net assets (margin and collateral deposits) of $2 million. The consolidated statements of cash flows for the years ended December 31, 2007 and 2006 have been retroactively restated to reflect the balance sheet changes, which had no impact on total operating cash flows from continuing operations.

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

In September 2006, the FASB issued SFAS No. 157, which clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SCE adopted SFAS No. 157 effective January 1, 2008. The adoption did not result in any retrospective adjustments to its consolidated financial statements. The accounting requirements for employers' pension and other postretirement benefit plans were effective at the end of 2008, which was the next measurement date for these benefit plans. SCE will adopt this standard for nonrecurring nonfinancial assets and liabilities (AROs) measured or disclosed at fair value during the first quarter of 2009. Since this standard is applied prospectively, AROs existing before the adoption of the standard will not be adjusted for nonperformance risk. For further discussion, see Note 10.

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

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

In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities." For asset transfers, the additional disclosure requirements primarily focus on the transferor's continuing involvement with transferred financial assets and the related risks retained. For VIEs, this position requires public enterprises to provide additional disclosures about their involvement with variable interest entities including the method for determining whether an enterprise is the primary beneficiary, the significant judgments and assumptions made and the details of any financial or other support provided to a VIE. This position was effective for reporting periods ending after December 15, 2008. The adoption did not have an impact on SCE's consolidated financial position, results of operations or cash flows. See Note 14 for disclosures pertaining to VIEs.

In December 2008, the FASB issued FSP EITF 99-20-1, "Amendments to the Impairment guidance of EITF Issue No. 99-20," which amends the guidance for purchased beneficial interests to achieve more consistent determination of whether an other-than-temporary impairment has occurred for available-for-sale or held-to-maturity debt securities. This pronouncement was effective for reporting periods ending after December 15, 2008. Because SCE already evaluates impairment for these securities in accordance with SFAS No. 115, the adoption did not have an impact on its consolidated financial position, results of operations or cash flows.

Accounting Pronouncements Not Yet Adopted

In December 2007, the FASB issued SFAS No. 160, which requires an entity to present minority interest that reflects the ownership interests in subsidiaries held by parties other than the entity, within the equity section but separate from the entity's equity in the consolidated financial statements. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interest be accounted for similarly as equity transactions; and, when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary be measured at fair value. SCE will adopt SFAS No. 160 in the first quarter of 2009 In accordance with this standard, SCE will reclassify minority interest to a component of shareholders' equity (at December 31, 2008 this amount was $380 million).

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

In December 2008, the FASB issued FSP FAS 132(R)-1, "Employers" Disclosures about Postretirement Benefit Plan Assets." This position requires additional plan asset disclosures about the major categories of assets, the inputs and valuation techniques used to measure fair value, the level within the fair value hierarchy, the effect of using significant unobservable inputs (Level 3) and significant concentrations of risk. This position is effective for years ending after December 15, 2009 and therefore, SCE will adopt FSP FAS 132(R)-1 at year-end 2009. FSP FAS 132(R)-1 will impact disclosures only and will not have an impact on SCE's consolidated results of operations, financial position or cash flows.

Nuclear Decommissioning

As a result of SCE's adoption of SFAS No. 143 in 2003, SCE recorded the fair value of its liability for AROs, primarily 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 recorded in accordance with SFAS No. 143 and the recovery of the related asset retirement costs through the rate-making process.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the NRC. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses currently expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2025 and 2027 for the Palo Verde units. 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. The earnings impact of amortization of the ARO asset included within the unamortized nuclear investment and accretion of the ARO liability, both established under SFAS No. 143, are deferred as increases to the ARO regulatory liability account, with no impact on earnings. See Note 8 for an analysis of the ARO liability.

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.

SCE's nuclear decommissioning trusts are accounted for in accordance with SFAS No. 115, and due to regulatory recovery of SCE nuclear decommissioning expense, rate-making accounting treatment is applied to all nuclear decommissioning trust activities in accordance with SFAS No. 71. As a result, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on operating revenue. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust asset and the related regulatory asset or liability and have no impact on operating revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the last day of each month compared to the last day of the previous month. If the fair value on both days is less than the cost for that security, SCE will recognize a realized 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 will recognize a related realized gain or loss, respectively. For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6 and "Nuclear Decommissioning Trusts" in Note 10.

Planned Major Maintenance

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

Property and Plant

Utility Plant

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

On November 26, 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects, DPV2, Tehachapi Transmission Project ("Tehachapi"), and Rancho Vista Substation Project ("Rancho Vista"). The order permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction of all three projects. On February 29, 2008, the FERC approved SCE's revision to its Transmission Owner Tariff to collect 100% of construction work in progress (CWIP) for these projects in rate base and earn a return on equity, rather than capitalizing AFUDC. SCE implemented the CWIP rate, subject to refund, on March 1, 2008. For further discussion, see "FERC Transmission Incentives" in Note 6.

Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.3% for 2008, 4.2% for 2007 and 4.2% for 2006.

AFUDC – equity was $54 million in 2008, $46 million in 2007 and $32 million in 2006 AFUDC – debt was $27 million in 2008, $24 million in 2007 and $18 million in 2006.

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.

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

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

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	38 years to 69 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	45 years
Other plant	5 years to 60 years	20 years

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

Nonutility Property

Nonutility property, including construction in progress, is capitalized at cost, including interest accrued on borrowed funds that finance construction. Capitalized interest was less than a million dollars in 2008, 2007 and 2006. Mountainview plant is included in nonutility property in accordance with the rate-making treatment. Capitalized interest is generally amortized over 30 years (the life of the purchase-power agreement under which Mountainview plant operates).

Depreciation and amortization is primarily computed on a straight-line basis over the estimated useful lives of nonutility properties. Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 3.9% for 2008, 3.9% for 2007 and 3.8% for 2006. The VIEs (commenced consolidation in March 31, 2004) compose a majority of nonutility property.

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 20 years
Building, plant and equipment	5 years to 30 years
Land easements	60 years

Asset Retirement Obligation

SCE accounts for its asset retirement obligations in accordance with in accordance with SFAS No. 143 and FIN 47. SCE's AROs related to decommissioning of its nuclear power facilities are based on site-specific studies. The initial establishment of a nuclear-related ARO is at fair value and results in a corresponding regulatory asset. See "Nuclear Decommissioning" above for further discussion. Over time, the liability is increased for accretion each period. SCE's conditional AROs are recorded at fair value in the period in which it is incurred if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. When the liability is initially recorded, the cost is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased for accretion each period, and the capitalized cost is depreciated over the useful life of the related asset. Settlement of an ARO liability, for an amount other than its recorded amount, results in a gain or loss.

Purchased-Power

From January 17, 2001 to December 31, 2002, the CDWR purchased power on behalf of SCE's customers for SCE's residual net short power position (the amount of energy needed to serve SCE's customers in excess of SCE's own generation and power-purchase contracts). Additionally, the CDWR signed long-term contracts that provide power for SCE's customers. Effective January 1, 2003, SCE resumed power procurement responsibilities for its residual net short position. SCE acts as a billing agent for the CDWR power, and any power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

Receivables

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

Regulatory Assets and Liabilities

In accordance with SFAS No. 71, SCE records regulatory assets, which represent probable future recovery of certain costs from customers through the rate-making process, and regulatory liabilities, which represent probable future credits to customers through the rate-making process. See Note 11 for additional disclosures related to regulatory assets and liabilities.

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: percentage of time worked, 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.

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

Revenue Recognition

Operating revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each reporting period. Rates charged to customers are based on CPUC-authorized and FERC-approved revenue requirements. CPUC rates are implemented upon final approval. FERC rates are often implemented on an interim basis at the time when the rate change is filed. Revenue collected prior to a final FERC approval decision is subject to refund. SCE's revenue requirements are based on its cost of service, referred to as base rate revenue requirement, and also provide recovery of pass-through costs under ratemaking mechanisms (balancing accounts) authorized by the CPUC. The base rate revenue requirement provides an opportunity to recover operation and maintenance expenses, capital-related carrying costs and earn an authorized rate of return. The revenue requirement for pass-through costs provides recovery of fuel and purchased-power expenses, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses and depreciation expense related to certain projects. SCE recognizes operating revenue equal to its authorized base rate revenue requirement and equal to actual costs incurred for pass-through costs.

The CPUC-authorized decoupling revenue mechanisms allow differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers therefore such differences do not impact operating revenue. Differences between authorized operating costs included in SCE's base rate revenue requirement and actual operating costs incurred, other than pass-through costs, do not impact operating revenue, but have an impact on earnings.

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE because SCE is acting as an agent for these transactions. Furthermore, amounts billed to ($2.2 billion in 2008, $2.3 billion in 2007 and $2.5 billion in 2006) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and a portion of direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as operating revenue by SCE.

Sales and Use Taxes

SCE bills certain sales and use taxes levied by state or local governments to its customers. Included in these sales and use taxes are franchise fees, which SCE pays to various municipalities (based on contracts with these municipalities) in order to operate within the limits of the municipality. SCE bills these franchise fees to its customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SCE's ability to collect from the customer, are accounted for on a gross basis and reflected in operating revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as operating revenue were $103 million, $104 million and $107 million for the years ended December 31, 2008, 2007 and 2006, respectively. When SCE acts as an agent, and the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are being remitted to the taxing authorities and are not recognized as operating revenue.

Short-term Investments

At different times during 2007 and 2006, SCE held various variable rate demand notes related to short-term cash management activities. The interest rate process for these securities allow for a resetting of interest rates related to changes in terms and/or credit quality, similar to cash and cash equivalents. In accordance with SFAS No. 115, if on hand at the end a period, these notes would be classified as short-term available-for-sale investment securities and recorded at fair value. There were no outstanding notes as of December 31, 2008 and 2007. Both sales and purchases of the notes were $7 billion and $6 billion for the years ended December 31, 2007 and 2006, respectively. There were no realized or unrealized gains or losses.

Stock-Based Compensation

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

On April 26, 2007, Edison International's shareholders approved a new incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. No additional awards were granted under Edison International's prior stock-based compensation plans on or after April 26, 2007, and all future issuances will be made under the new plan. The maximum number of shares of Edison International's common stock that may be issued or transferred pursuant to awards under the new incentive plan is 8.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued. As of December 31, 2008, Edison International had approximately 5.8 million shares remaining for future issuance under its stock-based compensation plans. For further discussion see "Stock-Based Compensation" in Note 5.

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. SCE implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, the new accounting standard was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. The new accounting standard resulted in the recognition of expense for all stock-based compensation awards. In addition, SCE elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards." Prior to adoption of SFAS No. 123(R), SCE presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other liabilities" in the consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $4 million, $28 million and $17 million of excess tax benefits are classified as financing cash flows in 2008, 2007 and 2006, respectively. Due to the adoption of SFAS No. 123(R), SCE recorded a cumulative effect adjustment that increased net income by less than $1 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates

Prior to January 1, 2006, SCE accounted for these plans using the intrinsic value method. Upon grant, no stock-based compensation cost for stock options was reflected in net income, as the grant date was the measurement date, and all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Previously, stock-based compensation cost for performance shares was remeasured at each reporting period and related compensation expense was adjusted. As discussed above, effective January 1, 2006, SCE implemented a new accounting standard that requires companies to use the fair value accounting method for stock-based compensation resulting in the recognition of expense for all stock-based compensation awards. SCE recognizes stock-based compensation expense on a straight-line basis over the requisite service period. Because SCE capitalizes a portion of cash-based compensation and SFAS No. 123(R) requires stock-based compensation to be recorded similarly to cash-based compensation, SCE capitalizes a portion of its stock-based compensation related to both unvested awards and new awards. SCE recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, SCE recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006, to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation will be recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement. If SCE recognized stock-based compensation expense for awards granted prior to January 1, 2006, over a period to the date the participant first became eligible for retirement, stock-based compensation expense would have decreased $1 million and $4 million for 2007 and 2006, respectively.

Note 2. Derivative Instruments and Hedging Activities

SCE is exposed to commodity price risk associated with its purchases for additional capacity and ancillary services to meet its peak energy requirements as well as exposure to natural gas prices associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including the Mountainview plant. SCE's realized gains and losses arising from derivative instruments are reflected in purchased-power expense and are recovered through the ERRA mechanism. Unrealized gains and losses have no impact on purchased-power expense due to regulatory mechanisms. As a result, realized and unrealized gains and losses do not affect earnings, but may temporarily affect cash flows. The following is a summary of purchased-power expense:

In millions Year ended December 31,	2008	2007	2006
Purchased-power	**$ 3,816**	$ 3,179	$ 2,940
Realized losses on economic hedging activities – net	**60**	132	339
Energy settlements and refunds	**(31)**	(76)	(180)
Total purchased-power expense	**$ 3,845**	$ 3,235	$ 3,099

Unrealized (gains) losses on economic hedging were $638 million in 2008, $(94) million in 2007, and $237 million in 2006. Changes in realized and unrealized gains and losses on economic hedging activities were primarily due to significant decreases in forward natural gas prices in 2008 compared to 2007. Changes in realized and unrealized gains and losses on economic hedging activities in 2007 compared to 2006 were primarily due to changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market in 2007.

Note 3. Liabilities and Lines of Credit

Long-Term Debt

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2008, SCE was in compliance with this debt covenant. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

Long-term debt is:

In millions December 31,	2008	2007
First and refunding mortgage bonds:		
2009 – 2038 (4.65% to 6.00% and variable)	**$ 4,875**	$ 3,375
Pollution-control bonds:		
2015 – 2035 (2.9% to 5.55% and variable)	**1,196**	1,196
Bonds repurchased	**(249)**	(37)
Debentures and notes:		
2010 – 2053 (5.06% to 7.625%)	**557**	557
Long-term debt due within one year	**(150)**	—
Unamortized debt discount – net	**(17)**	(10)
Total	**$ 6,212**	$ 5,081

Note: Rates and terms as of December 31, 2008

The interest rates on one issue of SCE's pollution control bonds insured by FGIC, totaling $249 million, were reset every 35 days through an auction process. Due to a loss of confidence in the creditworthiness of the bond insurers, there was a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds increased. Consequently, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and the remaining $212 million during the first three months of 2008. In March 2008, SCE converted the issue to a variable rate mode and terminated the FGIC insurance policy. SCE continues to hold the bonds which remain outstanding and have not been retired or cancelled.

Long-term debt maturities and sinking-fund requirements for the next five years are: 2009 – $150 million; 2010 – $250 million; 2011 – zero, 2012 – zero and 2013 – zero.

Short-Term Debt

Short-term debt is generally used to finance fuel inventories, balancing account undercollections and general, temporary cash requirements including power purchase payments. At December 31, 2008, the outstanding short-term debt was $1.89 billion at a weighted-average interest rate of 0.67%. This short-term debt is supported by a $2.5 billion credit line. At December 31, 2007, the outstanding short-term debt was $500 million at a weighted-average interest rate of 5.29%. This short-term debt was supported by a $2.5 billion credit line. See below in "Credit Agreements."

Credit Agreements

In March 2008, SCE amended its $2.5 billion credit facility, extending the maturity to February 2013. The related borrowings are classified as short-term debt as it is expected to be repaid by year-end 2009. The amendment also provides four extension options which, if all exercised, and agreed to by lenders, will result in a final termination in February 2017.

On September 15, 2008, Lehman Brothers Holdings filed for protection under Chapter 11 of the U.S. Bankruptcy Code. A subsidiary of Lehman Brothers Holdings, Lehman Brothers Bank, FSB, is one of the lenders in SCE's credit agreement representing a total commitment of $106 million. Lehman Brothers Bank, FSB, had funded $25 million of SCE's borrowing request during the second quarter of 2008 but declined SCE's requests during the second half of 2008 for funding of approximately $57 million.

The following table summarizes the status of the SCE credit facility:

In millions **Year ended December 31,**	**2008**	2007
Commitment	**$ 2,500**	$ 2,500
Less: Unfunded commitment from Lehman Brothers subsidiary	**(81)**	—
	2,419	2,500
Outstanding borrowings	**(1,893)**	(500)
Outstanding letters of credit	**(141)**	(229)
Amount available	**$ 385**	$ 1,771

Note 4. Income Taxes

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

In millions **Year ended December 31,**	**2008**	2007	2006
Current:			
Federal	**$ 53**	$ 295	$ 681
State	**43**	94	159
	96	389	840
Deferred:			
Federal	**232**	(31)	(312)
State	**14**	(21)	(90)
	246	(52)	(402)
Total	**$ 342**	$ 337	$ 438

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

In millions December 31,	2008	2007
Deferred tax assets:		
Property-related	**497**	396
Regulatory balancing accounts	**436**	519
Unrealized gains and losses	**70**	393
Decommissioning	**168**	182
Pensions and PBOPs	**203**	177
Other	**439**	552
Total	**$ 1,813**	$ 2,219
Deferred tax liabilities:		
Property-related	**$ 3,493**	$ 3,155
Capitalized software costs	**231**	128
Regulatory balancing accounts	**433**	521
Unrealized gains and losses	**70**	394
Decommissioning	**148**	158
Other	**209**	273
Total	**$ 4,584**	$ 4,629
Accumulated deferred income tax liability – net	**$ 2,771**	$ 2,410
Classification of accumulated deferred income taxes – net:		
Included in deferred credits and other liabilities	**$ 2,918**	$ 2,556
Included in total current assets	**147**	146

The federal statutory income tax rate is reconciled to the effective tax rate from continuing operations as follows:

Year ended December 31,	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State tax – net of federal benefit	**3.5**	4.4	3.6
Property-related	**(6.1)**	(1.0)	(0.3)
Tax reserve adjustments	**0.7**	(4.8)	3.1
ESOP dividend payment	**(0.9)**	(0.8)	(0.9)
Resolution of state audit issue	**—**	—	(3.9)
Other	**(0.4)**	(2.0)	(2.0)
Effective tax rate	**31.8%**	30.8%	34.6%

The composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for all periods presented. The lower effective tax rate of 31.8% in 2008 as compared to the statutory rate was primarily due to software and property related flow through deductions. The lower effective tax rate of 30.8% in 2007 as compared to the statutory rate was primarily due to reductions made to the income tax reserve to reflect progress made in an administrative appeals process with the IRS related to the income tax treatment of certain costs associated with environmental remediation and to reflect a settlement of state tax audit issues. The lower effective tax rate of 34.6% in 2006 as compared to the statutory rate was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue partially offset by tax reserve accruals.

Accounting for Uncertainty in Income Taxes

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

Unrecognized Tax Benefits Tabular Disclosure

The following table provides a reconciliation of unrecognized tax benefits from January 1 to December 31:

In millions	2008	2007
Balance at January 1	**$ 1,950**	$ 1,985
Tax positions taken during the current year		
Increases	**111**	63
Decreases	**—**	—
Tax positions taken during a prior year		
Increases	**162**	124
Decreases	**(157)**	(222)
Decreases for settlements during the period	**—**	—
Reductions for lapses of applicable statute of limitations	**—**	—
Balance at December 31	**$ 2,066**	$ 1,950

The unrecognized tax benefits in the table above reflects affirmative claims related to timing differences of $1.5 billion and $1.6 billion, at December 31, 2008 and 2007, respectively, that have been claimed on amended tax returns, but have not met the recognition threshold pursuant to FIN 48 and have been denied by the IRS as part of their examinations. These affirmative claims remain unpaid by the IRS and no receivable has been recorded. Edison International has vigorously defended these affirmative claims in IRS administrative appeals proceedings and these claims are included in the ongoing Global Settlement negotiations.

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

The total amount of unrecognized tax benefits as of December 31, 2008 and 2007, respectively, that if recognized, would have an effective tax rate impact is $60 million and $65 million, respectively.

Accrued Interest and Penalties

The total amounts of accrued interest and penalties related to SCE's income tax reserve were $120 million and $96 million as of December 31, 2008 and 2007, respectively. The after-tax interest expense (income) recognized and included in income tax expense was $14 million and $(24) million in 2008 and 2007, respectively.

California Apportionment

In December 2006, Edison International reached a settlement with the California Franchise Tax Board regarding the sourcing of gross receipts from the sale of electric services for California state tax apportionment purposes for tax years 1981 to 2004. In 2006, SCE recorded a $49 million benefit related to a tax reserve adjustment as a result of this settlement. In the FIN 48 adoption, a $54 million benefit was recorded related to this same issue. In addition, Edison International received a net cash refund of approximately $52 million in April 2007.

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

In the normal course, Edison International's federal income tax returns are examined by the IRS and Edison International challenges deficiency adjustments, asserted as part of an examination, to the Administrative Appeals branch of the IRS (IRS Appeals) to the extent Edison International believes its tax reporting positions properly complied with the relevant tax law and that the IRS' basis for making such adjustments lacks merit. Edison International has challenged certain IRS deficiency adjustments, asserted as part of the examination of tax years 1994 – 1999 with IRS Appeals. Edison International has also been under active IRS examination for tax years 2000 – 2002 and during the third quarter of 2008, the IRS commenced an examination of tax years 2003 – 2006. In addition, the statute of limitations remains open for tax years 1986 – 1993, which has allowed Edison International to file certain affirmative claims related to these tax years.

Most of the tax positions that Edison International is addressing with IRS Appeals relate to the timing of when deductions for federal income tax purposes are allowed to be reflected on filed income tax returns and, as such, any deductions not sustained would be deductible on future tax returns filed by Edison International. However, any penalties and interest associated with disallowed deductions would result in a permanent cost. Edison International has also filed affirmative claims with respect to certain tax years 1986 through 2005 with the IRS and state tax authorities. At this time, there has not been a final determination of these affirmative claims by the IRS or state tax authorities. Benefits, if any, associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when Edison International would make an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement of the affirmative claim is consummated with the tax authority. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

Edison International has been engaged in settlement negotiations with the IRS to reach a Global Settlement described below of all unresolved tax disputes and affirmative claims for tax years 1986 – 2002.

In addition to the IRS audits, Edison International's California and other state income tax returns are, in the normal course, subjected to examination by the California Franchise Tax Board and the other state tax authorities. The Franchise Tax Board has substantially completed its examination of all tax years through 2002 and is currently awaiting resolution of the IRS audit before finalizing the audit for these tax years. Edison International is currently under active examination for tax years 2003 – 2004 and remains subject to examination by the California Franchise Tax Board for tax years 2005 and forward.

Edison International filed amended California Franchise tax returns for tax years 1997 – 2002 to mitigate the possible imposition of California non-economic substance penalty provisions on transactions that may be considered as Listed or substantially similar to Listed Transactions described in an IRS notice that was published in 2001. These transactions include an SCE subsidiary contingent liability company transaction, described below. Edison International filed these amended returns under protest retaining its appeal rights.

Global Settlement

As previously disclosed, Edison International has negotiated the material terms of a Global Settlement with the IRS which, if consummated, would resolve all outstanding tax disputes for open tax years 1986 through 2002, including certain affirmative claims for unrecognized tax benefits. Consummation of the Global Settlement is subject to review by the Staff of the Joint Committee on Taxation, a committee of the United States Congress (the "Joint Committee"). The IRS submitted the pertinent terms of the Global Settlement to the Joint Committee during the fourth quarter of 2008, and its response is currently pending. Edison International cannot predict the timing of when the Joint Committee will complete its review. Moreover, Edison International cannot predict whether the Joint Committee will concur with the settlement terms negotiated by the IRS for the Global Settlement issues and whether any non-concurrence would result in the IRS proposing different settlement terms.

If and when Edison International and the IRS consummate a settlement, Edison International will file amended tax returns with the Franchise Tax Board and other state administrative agencies, for those states in which Edison International has an income tax filing requirement, to reflect the respective state income tax impact of the settlement terms.

The issues discussed below are included in the ongoing IRS examination and appeals process and are included in the scope of issues being addressed as part of the Global Settlement process.

Balancing Account Over-Collections

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

Contingent Liability Company

The IRS has asserted tax deficiencies and penalties of $53 million and $22 million, respectively, for tax years 1997 – 1999 with respect to a transaction entered into by a former SCE subsidiary which the IRS has asserted to be substantially similar to a Listed Transaction described by the IRS as a contingent liability company.

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

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

Note 5. Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $65 million in 2008, $61 million in 2007 and $57 million in 2006.

Pension Plans and Postretirement Benefits Other Than Pensions

SFAS No. 158 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). SCE adopted SFAS No. 158 as of December 31, 2006. In accordance with SFAS No. 71, SCE recorded regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates.

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 $39 million for the year ended December 31, 2009. The fair value of the plan assets is determined primarily by quoted market prices.

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. Changes in the plan's funded status affect the assets and liabilities recorded on the balance sheet in accordance with SFAS No. 158. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts. The Pension Protection Act of 2006 establishes new minimum funding standards and restricts plans underfunded by more than 20% from providing lump sum distributions and adopting amendments that increase plan liabilities.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2008	2007
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 3,106**	$ 3,176
Service cost	**104**	100
Interest cost	**184**	171
Amendments	**—**	(5)
Actuarial gain	**(2)**	(90)
Special termination benefits	**—**	2
Benefits paid	**(217)**	(248)
Projected benefit obligation at end of year	**$ 3,175**	$ 3,106
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 3,459**	$ 3,340
Actual return (loss) on plan assets	**(1,059)**	284
Employer contributions	**55**	83
Benefits paid	**(217)**	(248)
Fair value of plan assets at end of year	**$ 2,238**	$ 3,459
Funded status at end of year	**$ (937)**	$ 353
Amounts recognized in the consolidated balance sheets consist of:		
Long-term assets	**$ —**	$ 445
Current liabilities	**(5)**	(5)
Long-term liabilities	**(932)**	(87)
	$ (937)	$ 353
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	**$ 1**	$ 1
Net loss	**23**	24
	$ 24	$ 25
Amounts recognized as a regulatory asset (liability):		
Prior service cost	**$ 33**	$ 49
Net gain	**951**	(357)
	$ 984	$ (308)
Total not yet recognized as expense	**$ 1,008**	$ (283)
Accumulated benefit obligation at end of year	**$ 2,898**	$ 2,773
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 3,175**	$ 92
Accumulated benefit obligation	**$ 2,898**	$ 75
Fair value of plan assets	**$ 2,238**	—
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	**6.25%**	6.25%
Rate of compensation increase	**5.0%**	5.0%

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

In millions Year ended December 31,	2008	2007	2006
Service cost	**$ 104**	$ 100	$ 102
Interest cost	**184**	171	169
Expected return on plan assets	**(249)**	(237)	(225)
Special termination benefits	**—**	2	8
Amortization of prior service cost	**17**	17	16
Amortization of net loss	**3**	3	3
Expense under accounting standards	**$ 59**	$ 56	$ 73
Regulatory adjustment – deferred	**(5)**	(3)	(10)
Total expense recognized	**$ 54**	$ 53	$ 63

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

In millions Year ended December 31,	2008	2007
Net loss (gain)	**$ (2)**	$ 5
Prior service cost	**—**	—
Amortization of prior service cost	**—**	—
Amortization of net loss	**(3)**	(3)
Total recognized in other comprehensive (income) loss	**$ (5)**	$ 2
Total recognized in expense and other comprehensive income	**$ 49**	$ 55

Effective with the adoption of SFAS No. 158, as of December 31, 2006, and in accordance with SFAS No. 71, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. The estimated amortization amounts for 2009 are $17 million for prior service cost and $52 million for net gain including zero and $3 million respectively, reclassified from other comprehensive income.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits.

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

Year ended December 31,	2008	2007	2006
Weighted-average assumptions:			
Discount rate	**6.25%**	5.75%	5.5%
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 Year ending December 31,	
2009	$ 279
2010	$ 284
2011	$ 297
2012	$ 303
2013	$ 300
2014 – 2018	$ 1,480

The following are asset allocations by investment category:

	Target for 2009	December 31, 2008	December 31, 2007
United States equities	39%	**41%**	47%
Non-United States equities	17%	**22%**	25%
Private equities	4%	**4%**	2%
Fixed income	40%	**33%**	26%

Postretirement Benefits Other Than Pensions

Most nonunion employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits. Eligibility depends on a number of factors, including the employee's hire date. The expected contributions (all by the employer) to the PBOP trust are $125 million for the year ended December 31, 2009. The fair value of plan assets is determined primarily by quoted market prices.

Volatile market conditions have affected the value of SCE's trusts established to fund its future other postretirement benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trust declined 33% during 2008. This reduction in the value of plan assets resulted in an increase in the plan underfunded status and will also result in increased future expense and increased future contributions. Changes in the plan's funded status affect the assets and liabilities recorded on the balance sheet in accordance with SFAS No. 158. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to this trust.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2008	2007
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,182**	$ 2,178
Service cost	**38**	43
Interest cost	**130**	125
Amendments	**—**	6
Actuarial gain	**(26)**	(77)
Special termination benefits	**—**	1
Plan participants' contributions	**11**	8
Medicare Part D subsidy received	**5**	4
Benefits paid	**(93)**	(106)
Benefit obligation at end of year	**$ 2,247**	$ 2,182
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,815**	$ 1,743
Actual return (loss) on assets	**(557)**	117
Employer contributions	**31**	49
Plan participants' contributions	**11**	8
Medicare Part D subsidy received	**5**	4
Benefits paid	**(93)**	(106)
Fair value of plan assets at end of year	**$ 1,212**	$ 1,815
Fund status at end of year	**$ (1,035)**	$ (367)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	**$ (17)**	$ (18)
Long-term liabilities	**(1,018)**	(349)
	$ (1,035)	$ (367)
Amounts recognized in accumulated other comprehensive loss (income) consist of:		
Prior service cost	**$ —**	$ —
Net loss	**—**	—
	$ —	$ —
Amounts recognized as a regulatory asset (liability):		
Prior service cost (credit)	**$ (178)**	$ (206)
Net loss	**1,076**	437
	$ 898	$ 231
Total not yet recognized as expense	**$ 898**	$ 231
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	**6.25%**	6.25%
Assumed health care cost trend rates:		
Rate assumed for following year	**8.75%**	9.25%
Ultimate rate	**5.5%**	5.0%
Year ultimate rate reached	**2016**	2015

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

In millions Year ended December 31,	2008	2007	2006
Service cost	**$ 38**	$ 43	$ 43
Interest cost	**130**	125	116
Expected return on plan assets	**(122)**	(119)	(106)
Special termination benefits	**—**	1	4
Amortization of prior service cost (credit)	**(29)**	(29)	(29)
Amortization of net loss	**14**	28	41
Total expense	**$ 31**	$ 49	$ 69

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

In millions Year ended December 31,	2008	2007
Net loss	**$ —**	$ —
Prior service cost	**—**	—
Amortization of prior service cost (credit)	**—**	—
Amortization of net loss	**—**	—
Total recognized in other comprehensive income	**$ —**	$ —
Total recognized in expense and other comprehensive income	**$ 31**	$ 49

Effective with the adoption of SFAS No. 158, as of December 31, 2006, and in accordance with SFAS No. 71, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates. The estimated amortization amounts for 2009 are $(29) million for prior service cost (credit) and $61 million for net loss.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits.

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

Year ended December 31,	2008	2007	2006
Discount rate	**6.25%**	5.75%	5.5%
Expected return on plan assets	**7.0%**	7.0%	7.0%
Assumed health care cost trend rates:			
Current year	**9.25%**	9.25%	10.25%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2015**	2015	2011

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2008 by $247 million and annual aggregate service and interest costs by $17 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2008 by $222 million and annual aggregate service and interest costs by $15 million.

The following benefit payments are expected to be paid:

In millions	Year ending December 31,	Before Subsidy*	Net
2009		$ 102	$ 97
2010		112	106
2011		122	115
2012		131	123
2013		139	131
2014 – 2018		821	765

* Medicare Part D prescription drug benefits

The following are asset allocations by investment category:

Asset allocations are:

	Target for 2009	December 31, 2008	2007
United States equities	45%	**58%**	62%
Non-United States equities	17%	**11%**	14%
Private equities	1%	**—**	—
Fixed income	37%	**31%**	24%

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. As a result of the significant increase in global financial market volatility, during 2008 and in early 2009, the trusts' investment committee approved interim changes in target asset allocations. SCE employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is managed through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. SCE also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States Equities: Common and preferred stock 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.

Private Equity: Limited partnerships that invest in nonpublicly traded entities.

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

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

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

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

Capital Markets Return Forecasts

Capital markets return forecasts are based on a long-term equilibrium forecast from an independent firm, as well as a separate analysis of expected equilibrium returns. The independent firm uses its research and judgment to determine long-term equilibrium forecasts. A core set of macroeconomic variables is used including real GDP growth, personal consumption expenditures, the federal funds target rate, dividend yield, and the Treasury yield curve. Fixed income, equity and private equity returns are determined from these factors. In addition, a separate analysis of equilibrium returns is made. The estimated total return for fixed income is based on an equilibrium yield for intermediate United States government bonds plus a premium for exposure to non-government bonds in the broad fixed income market. The equilibrium yield is based on analysis of historic and projected data and is consistent with experience over various economic environments. The premium of the broad market over United States government bonds is a historic average premium. The estimated rate of return for equity includes a 3% premium over the estimated total return of intermediate United States government bonds. The rate of return for private equity is estimated to be a 5% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Stock-Based Compensation

Total stock-based compensation expense, net of amounts capitalized, (reflected in the caption "Other operation and maintenance" on the consolidated statements of income) was $15 million, $21 million and $27 million for 2008, 2007 and 2006, respectively. The income tax benefit recognized in the consolidated statements of income was $6 million, $8 million and $11 million for 2008, 2007 and 2006, respectively. Total stock-based compensation cost capitalized was $3 million, $4 million and $6 million for 2008, 2007 and 2006, respectively.

Stock Options

Under various plans, SCE has granted stock options at exercise prices equal to the average of the high and low price and, beginning in 2007, at the closing price at the grant date. Edison International may grant stock options and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants, as discussed in "Stock-Based Compensation" in Note 1. Stock-based compensation expense, net of amounts capitalized, associated with stock options was $12 million, $12 million and $20 million for 2008, 2007 and 2006, respectively. See "Stock-Based Compensation" in Note 1 for further discussion.

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 2008 have no dividend equivalent rights. Unless transferred to nonqualified deferral plan accounts, dividend equivalents accumulate without interest. Dividend equivalents are paid only on options that vest, including options that are unexercised. 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.

Year ended December 31,	2008	2007	2006
Expected terms (in years)	**7.4**	7.5	9 to 10
Risk-free interest rate	**2.6% – 3.8%**	4.6% – 4.8%	4.3% – 4.7%
Expected dividend yield	**2.3% – 3.9%**	2.1% – 2.4%	2.3% – 2.8%
Weighted-average expected dividend yield	**2.5%**	2.4%	2.4%
Expected volatility	**17% – 19%**	16% – 17%	16% – 17%
Weighted-average volatility	**17.3%**	16.5%	16.3%

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. In 2006 – 2008, expected volatility is based on the historical volatility of Edison International's common stock for the most recent 36 months.

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

		Weighted-Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2007	6,260,384	$ 31.21		
Granted	1,189,404	$ 49.88		
Expired	(13,905)	$ 46.85		
Forfeited	(94,032)	$ 45.67		
Exercised	(645,078)	$ 25.89		
Transfer to associate	(296,039)	$ 37.45		
Outstanding at December 31, 2008	**6,400,734**	**$ 34.58**	**6.30**	
Vested and expected to vest at December 31, 2008	6,173,098	$ 34.23	6.22	$ 71,607,937
Exercisable at December 31, 2008	**3,717,758**	**$ 26.85**	**5.14**	**$ 70,563,047**

Stock options granted in 2007 and 2008 do not accrue dividend equivalents.

The weighted-average grant-date fair value of options granted during the 2008, 2007 and 2006 was $10.19, $11.36 and $14.42, respectively. The total intrinsic value of options exercised during 2008, 2007 and 2006 was $13 million, $69 million and $43 million, respectively. At December 31, 2008, there was $13 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 2008, 2007 and 2006 was $12 million, $14 million and $27 million, respectively.

The amount of cash used to settle stock options exercised was $30 million, $125 million and $88 million for 2008, 2007 and 2006, respectively. Cash received from options exercised for 2008, 2007 and 2006 was $17 million, $56 million and $45 million, respectively. The estimated tax benefit from options exercised for 2008, 2007 and 2006 was $5 million, $28 million and $17 million.

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2006, March 2007 and March 2008, and vest at the end of December 2008, 2009 and 2010, respectively. Performance shares awarded in 2005 and 2006 accrue dividend equivalents which accumulate without interest, and will be payable in cash following the end of the performance period when the performance shares are paid. Edison International has discretion to pay certain dividend equivalents in Edison International common stock. Performance shares awarded in 2007 and 2008 contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's common stock performance relative to the performance of a specified group of 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. Dividend equivalents will be adjusted to correlate to the actual number of performance shares paid. 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. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares 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, as discussed in "Stock-Based Compensation" in Note 1. Stock-based compensation expense, net of amounts capitalized, associated with performance shares was less than zero, $6 million and $7 million for 2008, 2007, and 2006, respectively. The amount of cash used to settle performance shares classified as equity awards was $5 million, $11 million and $19 million for 2008, 2007 and 2006, respectively. In 2007 we changed the classification of the cash paid for the settlements of performance shares from common stock to retained earnings to conform with the classification for settlements of stock option exercises.

The performance shares' fair value is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires a risk-free interest rate and an expected volatility rate assumption. The risk-free interest rate is based on a 52-week historical average of the three-year zero coupon U.S. Treasury issued STRIPs (separate trading of registered interest and principal of securities) and is used as a proxy for the expected return for the specified group of companies. Volatility is based on the historical volatility of Edison International's common stock for the recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

Edison International's risk-free interest rate used to determine the grant date fair values for the 2008, 2007 and 2006 performance shares classified as share-based equity awards was 3.9%, 4.8% and 4.1%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2008, 2007 and 2006 performance shares classified as share-based equity awards was 17.4%, 16.5% and 16.2%, respectively. The portion of performance shares classified as share-based liability awards are revalued at each reporting period. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2008 was to 0.8% and 19.2%, respectively for 2008 performance shares. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2007 was 4.3% and 17.1%, respectively for 2007 performance shares.

The total intrinsic value of performance shares settled during 2008, 2007 and 2006 was $11 million, $23 million and $38 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2008, 2007 and 2006 of $3 million, $5 million and $9 million, respectively. At

December 31, 2008, there was $2 million (based on the December 31, 2008 fair value of performance shares classified as liability awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair values of performance shares vested during 2008, 2007 and 2006 were $2 million, $8 million and $14 million, respectively.

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

	Performance Shares	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2007	85,243	$ 55.01
Granted	47,101	$ 55.55
Forfeited	(46,209)	$ 53.36
Transferred to associate	(7,618)	$ 53.41
Paid out	—	$ —
Nonvested at December 31, 2008	**78,517**	**$ 56.45**

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2008, 2007 and 2006 was $55.55, $57.70 and $52.76, respectively.

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

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2007	85,387	
Granted	46,957	
Forfeited	(46,209)	
Transferred to associate	(7,618)	
Paid out	—	
Nonvested at December 31, 2008	**78,517**	**$ 3.75**

Note 6. Commitments and Contingencies

Lease Commitments

In accordance with EITF No. 01-8, power contracts signed or modified after June 30, 2003, need to be assessed for lease accounting requirements. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. As of December 31, 2005, SCE had six power contracts classified as operating leases. In 2006, SCE modified 62 power contracts. No contracts were modified in 2007 and 2008. The modifications to the contracts resulted in a change to the contractual terms of the contracts at which time SCE reassessed these power contracts under EITF No. 01-8 and determined that the contracts are leases and subsequently met the requirements for operating leases under SFAS No. 13. These power contracts had previously been grandfathered relative to EITF No. 01-8 and did not meet the normal purchases and sales exception. As a result, these contracts were recorded on the consolidated balance sheets at fair value in accordance with SFAS No. 133. Due to regulatory mechanisms, fair value changes did not affect earnings. At the time of modification, SCE had assets and liabilities related to mark-to-market gains or losses. Under SFAS No. 133, the assets and liabilities were reclassified to a lease prepayment or accrual and were included in the cost basis of the lease. The lease prepayment and accruals are being amortized over the life of the lease on a straight-line basis. At December 31, 2008, the net liability was $64 million. At December 31, 2008, SCE had 69 power contracts classified as operating leases. Operating lease expense for power purchases was $328 million in 2008, $297 million in 2007, and $188 million in 2006. In addition, as of December 31, 2008, SCE had four power purchase contracts which met the requirements for capital leases. These capital leases have a net commitment of $1.22 billion at December 31, 2008 and $20 million at December 31, 2007. The total estimated capital lease executory costs and interest expense were $1.71 billion at December 31, 2008 and $20 million at December 31, 2007.

Other operating lease expense, primarily for vehicle leases, was $47 million in 2008, $39 million in 2007 and $31 million in 2006. The leases have varying terms, provisions and expiration dates.

The following are estimated remaining commitments for noncancelable operating leases, including power purchases, vehicles, office space, and other equipment:

In millions	Year ending December 31,	Power Contracts Operating Leases	Other Operating Leases
2009		$ 638	$ 51
2010		625	49
2011		458	42
2012		355	34
2013		349	29
Thereafter		2,000	93
Total		**$ 4,425**	**$ 298**

As discussed above, SCE modified numerous power contracts which increased the noncancelable operating lease future commitments and decreased the power purchase commitments below in "Other Commitments."

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 fair value of decommissioning SCE's nuclear power facilities is $2.9 billion as of December 31, 2008, based on site-specific studies performed in 2005 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $46 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 4.4% to 5.8%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates in the future. If the assumed return on trust assets is greater than estimated, funding amounts may be reduced through future decommissioning proceedings.

Decommissioning of San Onofre Unit 1 is underway and will be completed in three phases:
(1) decontamination and dismantling of all structures and some foundations; (2) spent fuel storage monitoring; and (3) fuel storage facility dismantling, removal of remaining foundations, and site restoration. Phase one was scheduled to continue through 2008. Phase two is expected to continue until 2026. Phase three will be conducted concurrently with the San Onofre Units 2 and 3 decommissioning projects. In February 2004, SCE announced that it discontinued plans to ship the San Onofre Unit 1 reactor pressure vessel to a disposal site until such time as appropriate arrangements are made for its permanent disposal. It will continue to be stored

at its current location at San Onofre Unit 1. This action results in placing the disposal of the reactor pressure vessel in Phase three of the San Onofre Unit 1 decommissioning project.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds and are subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($59 million at December 31, 2008). Total expenditures for the decommissioning of San Onofre Unit 1 were $583 million from the beginning of the project in 1998 through December 31, 2008.

Decommissioning expense under the rate-making method was $46 million, $46 million and $32 million in 2008, 2007 and 2006, respectively. The ARO for decommissioning SCE's active nuclear facilities was $2.9 billion and $2.7 billion at December 31, 2008 and 2007, respectively.

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

Other Commitments

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

SCE has power purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table below). There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into power purchase settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the consolidated balance sheets.

Certain commitments for the years 2009 through 2013 are estimated below:

In millions	2009	2010	2011	2012	2013
Fuel supply	$ 207	$ 117	$ 158	$ 198	$ 192
Purchased power	$ 289	$ 368	$ 519	$ 681	$ 660

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $60 million through 2016 (approximately $7 million per year).

Indemnities

Indemnity Provided as Part of the Acquisition of Mountainview

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

Mountainview Filter Cake Indemnity

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

Other Indemnities

SCE provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. SCE's obligations under these agreements may be limited in terms of time and/or amount, and in some instances SCE may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. SCE has not recorded a liability related to these indemnities.

Contingencies

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

Environmental Remediation

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

SCE believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that SCE's financial position and results of operations would not be materially affected.

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

As of December 31, 2008, SCE's recorded estimated minimum liability to remediate its 24 identified sites was $41 million, of which $10 million was related to San Onofre. This remediation liability is undiscounted. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $173 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $40 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $31 million. Recorded costs were $29 million, $25 million and $14 million for 2008, 2007 and 2006, 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 or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

Edison International remains subject to examination and administrative appeals by the IRS for various tax years. See Note 4 for further details.

2009 FERC Rate Case

In an order issued in September 2008, the FERC accepted and made effective on March 1, 2009, subject to refund and settlement procedures, SCE's proposed revisions to its tariff, filed in the 2009 transmission rate case. The revisions reflected changes to SCE's transmission revenue requirement and transmission rates, as discussed below.

SCE requested a $129 million increase in its retail transmission revenue requirements (or a 39% increase over the current retail transmission revenue requirement) due to an increase in transmission capital-related costs and increases in transmission operating and maintenance expenses that SCE expects to incur in 2009 to maintain grid reliability. The transmission revenue requirement request is based on a return on equity of 12.7%, which is composed of a 12.0% base ROE and 0.7% in transmission incentives previously approved by the FERC (see "FERC Transmission Incentives" below for further information). SCE is unable to predict the revenue requirement that the FERC will ultimately authorize.

FERC Transmission Incentives

The Energy Policy Act of 2005 established incentive-based rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Pursuant to this act, in November 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects. These include 125 basis point ROE adders on SCE's proposed base ROE for SCE's

“DPV2” and Tehachapi transmission projects and a 75 basis point ROE adder for SCE’s Rancho Vista Substation Project (“Rancho Vista”).

In June 2007, the ACC denied the approval of the DPV2 project which resulted in an estimated two year delay of the project. SCE continues its efforts to obtain the regulatory approvals necessary to construct the DPV2 project and continues to evaluate its options, which include but are not limited to, filing a new application with the ACC and building the project in various phases.

The order also grants a 50 basis point ROE adder on SCE’s cost of capital for its entire transmission rate base in SCE’s next FERC transmission rate case for SCE’s participation in the CAISO. In addition, the order on incentives permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction, also known as CWIP, of all three projects and 100% recovery of prudently-incurred abandoned plant costs for two of the projects, if either are cancelled due to factors beyond SCE’s control.

In August 2008, the CPUC filed an appeal of the FERC incentives order at the DC Circuit Court of Appeals. The court issued a ruling on November 6, 2008, accepting the CPUC’s request that the court refrain from ruling on the CPUC’s appeal until a final FERC order is issued in the 2008 CWIP case (see “FERC Construction Work in Progress Mechanism” below for further information.)

FERC Construction Work in Progress Mechanism

FERC CWIP 2008

In February 2008, the FERC approved SCE’s revision to its tariff to collect 100% of CWIP in rate base for its Tehachapi, DPV2, and Rancho Vista, as authorized by FERC in its transmission incentives order discussed above which resulted in an authorized base transmission revenue requirement of $45 million subject to refund. In March 2008, the CPUC filed a petition for rehearing with the FERC on the FERC’s acceptance of SCE’s proposed ROE for CWIP and in another 2008 protest to an SCE compliance filing, requested an evidentiary hearing to be set to further review SCE’s costs. SCE cannot predict the outcome of the matters in this proceeding.

FERC CWIP 2009

SCE filed its 2009 CWIP rate adjustment in October 2008 proposing a reduction to its CWIP revenue requirement from $45 million to $39 million to be effective on January 1, 2009. Several parties, including the CPUC, filed protests to the October filing in November 2008, primarily contesting SCE’s proposed base ROE of 12.0%. The FERC issued an order in December 2008, allowing the proposed 2009 CWIP rates to go into effect on January 1, 2009, subject to refund, and directing that the 2009 CWIP ROE be made subject to the outcome of the pending 2008 FERC CWIP proceeding. The FERC also consolidated all issues other than ROE with SCE’s 2009 FERC rate case proceeding.

Four Corners CPUC Emissions Performance Standard Ruling

The emission performance standards adopted by the CPUC and CEC pursuant to SB 1368 prohibits SCE and other California load-serving entities from entering into long-term financial commitments with generators that emit more than 1,100 pounds of CO_2 per MWh, which would include most coal-fired plants. In January 2008, SCE filed a petition with the CPUC seeking clarification that the emission performance standard would not apply to capital expenditures required by existing agreements among the owners at Four Corners. The CPUC issued a proposed decision finding that the emission performance standard was not intended to apply to capital expenditures at Four Corners requested by SCE in its GRC for the period 2007 – 2011. In October 2008, the Assigned Commissioner and Administrative Law Judge issued a ruling withdrawing the proposed decision and seeking additional comment on whether the finding in the proposed decision should be changed and whether SCE should be allowed to recover such capital expenditures. SCE estimates that its share of capital expenditures approved by the owners at Four Corners since the GHG emission performance standard decision was issued in January 2007 is approximately $43 million, of which approximately $8 million had been expended through December 31, 2008. The ruling also directs SCE to explain why certain information was not included in its petition and why the failure to include such information should not be considered misleading in violation of CPUC rules. SCE filed its response and comments to the ruling in November and December 2008 and cannot predict the outcome of this proceeding or estimate the amount, if any, of penalties or disallowances that may be imposed.

ISO Disputed Charges

On April 20, 2004, the FERC issued an order concerning a dispute between the ISO and the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California over the proper allocation and characterization of certain transmission service related charges. The potential cost to SCE of the FERC order, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the pertinent time, is estimated to be approximately $20 million to $25 million, including interest. The order has been the subject of continuing legal proceedings since it was issued. SCE believes that the most recent substantive order FERC has issued in the proceedings correctly allocates responsibility for these ISO charges. However, SCE cannot predict the final outcome of the rehearing. If a subsequent regulatory decision changes the allocation of responsibility for these charges, and SCE is required to pay these charges as a transmission owner, SCE may seek recovery in its reliability service rates. SCE cannot predict whether recovery of these charges in its reliability service rates would be permitted.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the District Court against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion. In March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff but has not yet identified a specific amount of damages claimed. The case was stayed at the request of the parties in October 2004, but was reinstated to the active calendar in March 2008.

A related case against the U.S. Government is presently before the U.S. Supreme Court. The outcome of that case could affect the Navajo Nation's pursuit of claims against SCE. A decision from the U.S. Supreme Court is expected in mid-2009.

SCE cannot predict the outcome of the Tribe's complaints against SCE or the ultimate impact on these complaints of the on-going litigation by the Navajo Nation against the U.S. Government in the related case.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site.

Federal regulations require this secondary level of financial protection. The NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. Beginning October 29, 2008, the maximum deferred premium for each nuclear incident is approximately $118 million per reactor, but not more than approximately $18 million per reactor may be charged in any one year for each incident. The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident is adjusted for inflation at least once every five years. The most recent inflation adjustment took effect on October 29, 2008. Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further operating revenue.

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

Palo Verde Nuclear Generating Station Outage and Inspection

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

Procurement of Renewable Resources

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

It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules, such as banking of past surplus and earmarking of future deliveries from executed contracts. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

Under current CPUC decisions, potential penalties for SCE's inability to achieve its renewable procurement objectives for any year will be considered by the CPUC in the context of the CPUC's review of SCE's annual compliance filing. Under the CPUC's current rules, the maximum penalty for inability to achieve renewable procurement targets is $25 million per year. SCE does not believe it will be assessed penalties for 2008 or the prior years and cannot predict whether it will be assessed penalties for future years.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre (approximately $24 million, plus interest). SCE has also been paying a required quarterly fee equal to 0.1¢ per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Such interim storage for San Onofre is on-site.

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

Note 7. Accumulated Other Comprehensive Loss Information

SCE's accumulated other comprehensive income (loss) consists of:

	Pension and PBOP – Net Loss	Pension and PBOP – Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2006	$ (13)	$ (1)	$ (14)
Change for 2007	(1)	—	(1)
Balance at December 31, 2007	(14)	(1)	(15)
Change for 2008	1	—	1
Balance at December 31, 2008	**$ (13)**	**$ (1)**	**$ (14)**

SFAS No. 158 – postretirement benefits is discussed in "Pension Plans and Postretirement Benefits Other Than Pensions" in Note 5

Note 8. Property and Plant

Nonutility Property

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

In millions December 31,	2008	2007
Furniture and equipment	**$ 5**	$ 4
Building, plant and equipment	**1,681**	1,657
Land (including easements)	**30**	35
Construction in progress	**2**	5
	1,718	1,701
Accumulated provision for depreciation	**(765)**	(701)
Nonutility property – net	**$ 953**	$ 1,000

Asset Retirement Obligations

As a result of the adoption of SFAS No. 143 in 2003, SCE recorded the fair value of its liability for legal AROs, which was primarily related to the decommissioning of its nuclear power facilities. In addition, SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. 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 fair value of the nuclear decommissioning trusts was $2.5 billion at December 31, 2008. For a further discussion about nuclear decommissioning see "Nuclear Decommissioning Commitment" in Note 6 and "Nuclear Decommissioning Trusts" in Note 10.

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

In millions	2008	2007	2006
Beginning balance	**$ 2,877**	$ 2,749	$ 2,621
Accretion expense	**175**	168	160
Revisions	**(10)**	3	(3)
Liabilities added	**—**	—	41
Liabilities settled	**(35)**	(43)	(70)
Ending balance	**$ 3,007**	$ 2,877	$ 2,749

The ARO liability as of December 31, 2008 includes an ARO liability of $2.9 billion related to nuclear decommissioning

Note 9. Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions Year ended December 31,	2008	2007	2006
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 303**	$ 292	$ 321
Tax payments – net	**$ 251**	$ 299	$ 832
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	**$ —**	$ —	$ (331)
Pollution-control bonds issued	**$ —**	$ —	$ 331
Details of obligation under capital leases:			
Capital lease purchased	**$ —**	$ (10)	$ —
Capital lease obligation issued	**$ —**	$ 10	$ —
Dividends declared but not paid:			
Common stock	**$ 100**	$ 25	$ 60
Preferred and preference stock not subject to mandatory redemption	**$ 13**	$ 13	$ 9

Note 10. Fair Value Measurements

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

- Level 1 – Unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets and liabilities;
- Level 2 – Pricing inputs include quoted prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument; and
- Level 3 – Prices or valuations that require inputs that are both significant to the fair value measurements and unobservable.

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

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

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

Level 3 also includes derivatives that trade infrequently (such as FTRs and CRRs in the California market and over-the-counter derivatives at illiquid locations), and long-term power agreements. For illiquid FTRs, SCE reviews objective criteria related to system congestion and other underlying drivers and adjusts fair value when SCE concludes a change in objective criteria would result in a new valuation that better reflects the fair value. Recent auction prices are used to determine the fair value of short-term CRRs and the proprietary model is used for long-term CRRs. SCE recorded liquidity reserves against the long-term CRRs fair values since there were no quoted long-term market prices for the CRRs and insufficient evidence of long-term market prices.

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

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

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

In millions	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total at December 31, 2008
Assets at Fair Value					
Money market funds[2]	$ 1,486	$ —	$ —	$ —	$ 1,486
Derivative contracts	2	2	227	—	231
Nuclear decommissioning trusts[3]	1,502	1,026	—	—	2,528
Long-term disability plan	7	—	—	—	7
Total assets[4]	2,997	1,028	227	—	4,252
Liabilities at Fair Value					
Derivative contracts	(2)	(219)	(745)	72	(894)
Net assets (liabilities)	**$ 2,995**	**$ 809**	**$ (518)**	**$ 72**	**$ 3,358**

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

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

(3) Excludes net liabilities of $4 million of interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

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

The following table sets forth a summary of changes in the fair value of Level 3 derivative contracts, net for the year ended December 31, 2008:

In millions	2008
Fair value of derivative contracts, net at January 1, 2008	**$ (22)**
Total realized/unrealized losses:	
Included in earnings	**—**
Included in regulatory assets and liabilities[1]	**(532)**
Included in accumulated other comprehensive loss	**—**
Purchases and settlements, net	**167**
Transfers in or out of Level 3	**(18)**
Fair value of derivative contracts, net at December 31, 2008	**$ (405)**
Change during the period in unrealized losses related to net derivative contracts, held at December 31, 2008	**$ (460)**

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

Nuclear Decommissioning Trusts

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

Trust investments (at fair value) include:

In millions	Maturity Dates	December 31, 2008	December 31, 2007
Municipal bonds	2009 – 2044	**$ 629**	$ 561
Stocks	–	**1,308**	1,968
United States government issues	2009 – 2049	**304**	552
Corporate bonds	2009 – 2047	**260**	241
Short-term investments, primarily cash equivalents	2009	**23**	56
Total		**$ 2,524**	$ 3,378

Note: Maturity dates as of December 31, 2008.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (losses) were $(10) million, $143 million and $130 million in 2008, 2007 and 2006, respectively. Proceeds from sales of securities (which are reinvested) were $3.1 billion, $3.7 billion and $3.0 billion in 2008, 2007 and 2006, respectively. Unrealized holding gains, net of losses, were $618 million and $1.1 billion at December 31, 2008 and 2007, respectively. Approximately 92% of the cumulative trust fund contributions were tax-deductible.

The following table sets forth a summary of changes in the fair value of the trust for the year ended December 31, 2008:

In millions	2008
Balance at beginning of period	**$ 3,378**
Realized losses – net	**(65)**
Unrealized losses – net	**(545)**
Other-than-temporary impairment	**(317)**
Earnings and other	**73**
Balance at December 31, 2008	**$ 2,524**

The decrease in the trust investments was primarily due to net unrealized losses and other-than-temporary impairment resulting from a volatile stock market environment. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on operating revenue.

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

Fair Values of Financial Instruments

The carrying amounts and fair values of financial instruments are:

	December 31,			
	2008		2007	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Interest rate hedges	**$ —**	**$ —**	$ (33)	$ (33)
Commodity price assets	**231**	**231**	82	82
Commodity price liabilities	**(964)**	**(964)**	(77)	(77)
QF power contracts liabilities	**(2)**	**(2)**	(3)	(3)
Other:				
Decommissioning trusts	**2,524**	**2,524**	3,378	3,378
Long-term debt	**(6,212)**	**(6,566)**	(5,081)	(5,100)
Long-term debt due within one year	**(150)**	**(151)**	—	—

Fair values are based on: brokers' quotes and bank evaluations for interest rate hedges and long-term debt. See "Fair Value Measurements" above for discussion of valuation of derivatives and the decommissioning trusts.

In January and February 2008, SCE settled interest rate locks resulting in realized losses of $33 million. A related regulatory asset was recorded in this amount and SCE is amortizing and recovering this amount as interest expense associated with its 2008 financings.

Note 11. Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded operating revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Undercollections are recorded as regulatory balancing account assets. Overcollections 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 undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

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

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

In millions December 31,	2008	2007
Current:		
Regulatory balancing accounts	**$ 455**	$ 99
Energy derivatives	**138**	71
Purchased-power settlements	**—**	8
Deferred FTR proceeds	**9**	15
Other	**3**	4
	$ 605	$ 197
Long-term:		
Regulatory balancing accounts	**$ 29**	$ 15
Flow-through taxes – net	**1,337**	1,110
ARO	**224**	—
Unamortized nuclear investment – net	**375**	405
Nuclear-related ARO investment – net	**278**	297
Unamortized coal plant investment – net	**79**	94
Unamortized loss on reacquired debt	**309**	331
SFAS No. 158 pensions and other postretirement benefits	**1,882**	231
Energy derivatives	**723**	70
Environmental remediation	**40**	64
Other	**138**	104
	$ 5,414	$ 2,721
Total Regulatory Assets	**$ 6,019**	$ 2,918

SCE's regulatory assets related to energy derivatives are an offset to unrealized losses on recorded derivatives and an offset to lease accruals. SCE's regulatory assets related to purchased-power settlements were recovered through October 2008. SCE's regulatory assets related to deferred FTR proceeds represent the deferral of operating revenue associated with FTRs that SCE received as a transmission owner from the annual ISO FTR auction. The deferred FTR proceeds were recognized through March 2009. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to flow-through taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory asset related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's nuclear-related regulatory assets related to San Onofre are expected to be recovered by 2022. SCE's nuclear-related regulatory assets related to Palo Verde are expected to be recovered by 2027. SCE's net regulatory asset related to its unamortized coal plant investment is being recovered through June 2016. 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 30 years. SCE's regulatory asset related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be recovered through rates charged to customers. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

SCE's unamortized nuclear investment – net and unamortized coal plant investment – net regulatory assets earned a 8.75% and 8.77% return in 2008 and 2007, respectively.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

In millions December 31,	2008	2007
Current:		
Regulatory balancing accounts	**$ 1,068**	$ 967
Rate reduction notes – transition cost overcollection	**20**	20
Energy derivatives	**6**	10
Deferred FTR costs	**13**	19
Other	**4**	3
	$ 1,111	$ 1,019
Long-term:		
Regulatory balancing accounts	**$ 43**	$ —
ARO	**—**	793
Costs of removal	**2,368**	2,230
SFAS No. 158 pensions and other postretirement benefits	**—**	308
Energy derivatives	**—**	27
Employee benefit plans	**70**	75
	$ 2,481	$ 3,433
Total Regulatory Liabilities	**$ 3,592**	$ 4,452

Rate reduction notes – transition cost overcollection represents the nonbypassable rates charged to customers subsequent to the final principal payment of SCE's rate reduction bonds. These amounts will be refunded to ratepayers. SCE's regulatory liabilities related to energy derivatives are an offset to unrealized gains on recorded derivatives and an offset to a lease prepayment. SCE's regulatory liabilities related to deferred FTR costs represent the deferral of the costs associated with FTRs that SCE purchased during the annual ISO auction process. The FTRs provide SCE with scheduling priority in certain transmission grid congestion areas in the day-ahead market. The FTRs meet the definition of a derivative instrument and are recorded at fair value and marked to market each reporting period. Any fair value change for FTRs is reflected in the deferred FTR costs regulatory liability. The deferred FTR costs are recognized as FTRs are used or expire in various periods through March 2009. SCE's regulatory liability related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent operating revenue collected for asset removal costs that SCE expects to incur in the future. SCE's regulatory liability related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be returned to ratepayers in some future rate-making proceeding. SCE's regulatory liabilities related to employee benefit plan expenses represent pension costs recovered through rates charged to customers in excess of the amounts recognized as expense or the difference between these costs calculated in accordance with rate-making methods and these costs calculated in accordance with SFAS No. 87, and PBOP costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will be returned to ratepayers in some future rate-making proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process, or be applied as otherwise directed by the CPUC.

Note 12. Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2008	2007	2006
AFUDC	**$ 54**	$ 46	$ 32
Increase in cash surrender value of life insurance policies	**24**	23	21
Performance-based incentive awards	**3**	4	19
Other	**20**	16	13
Total other nonoperating income	**$ 101**	$ 89	$ 85
Various penalties	**$ 59**	$ 5	$ 23
Civic, political and related activities and donations	**42**	35	29
Other	**22**	5	8
Total other nonoperating deductions	**$ 123**	$ 45	$ 60

The 2008 increase in nonoperating deductions primarily resulted from a CPUC decision in September 2008 related to SCE incentives claimed under a CPUC-approved PBR mechanism. The decision required SCE to refund $28 million and $20 million related to customer satisfaction and employee safety reporting incentives, respectively, and further required SCE to forego claimed incentives of $20 million and $15 million related to customer satisfaction and employee safety reporting, respectively. The decision also required SCE to refund $33 million for employee bonuses related to the program and imposed a statutory penalty of $30 million. During the third quarter of 2008, SCE recorded a charge of $49 million, after-tax ($60 million, pre-tax) related to this decision.

Note 13. Jointly Owned Utility Projects

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

The following is SCE's investment in each project as of December 31, 2008:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 71	$ 13	60%
Pacific Intertie	310	103	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	554	454	48
Mohave (coal)	345	294	56
Palo Verde (nuclear)	1,824	1,501	16
San Onofre (nuclear)	4,833	4,024	78
Total	**$ 7,937**	**$ 6,389**	

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

Note 14. Variable Interest Entities

In December 2003, the FASB issued FIN 46(R). This Interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. Under this Interpretation, the primary beneficiary is the variable interest holder that absorbs a majority of expected losses; if no variable interest holder meets this criterion, then it is the variable interest holder that receives a majority of the expected residual returns. The primary beneficiary is required to consolidate the variable interest entity unless specific exceptions or exclusions are met.

Projects or Entities that are Consolidated

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts had 20-year terms at inception. The QFs sell electricity to SCE and steam to nonrelated parties. Under FIN 46(R), SCE consolidates these four projects.

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

Project	Capacity	Termination Date[1]	EME Ownership
Kern River	295 MW	June 2011	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

(1) SCE's power purchase agreements with Sycamore and Watson expired on December 31, 2007. Discussions on extending the power purchase and steam agreements are underway, but no assurance can be given that such discussions will lead to extensions of these agreements. As of January 1, 2009, these projects sell power to SCE under agreements with pricing set by the CPUC.

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

Entities with Unavailable Financial Information

SCE also has seven other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs under FIN 46(R). SCE might be considered to be the consolidating entity under this standard. SCE continues to attempt to obtain information for these projects in order to determine whether the projects should be consolidated by SCE. These entities are not legally obligated to provide the financial information to SCE and have declined to provide any financial information to SCE. Under the grandfather scope provisions of FIN 46(R), SCE is not required to apply this rule to these entities as long as SCE continues to be unable to obtain this information. The aggregate capacity dedicated to SCE for these projects is 263 MW. SCE paid $203 million in 2008 and $180 million in both 2007 and 2006 to these projects. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

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

SCE's authorized shares are: $100 cumulative preferred – 12 million shares, $25 cumulative preferred – 24 million shares and preference – 50 million shares. There are no dividends in arrears for the preferred stock or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the years ended December 31, 2008, 2007 and 2006. In January 2008, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. SCE retired this preferred stock in January 2008 and recorded a $2 million gain on the cancellation of reacquired capital stock (reflected in the caption "Additional paid-in capital on the consolidated balance sheets"). There is no sinking fund requirement for redemptions or repurchases of preferred stock.

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

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

Dollars in millions, except per-share amounts	December 31,		2008	2007
	December 31, 2008			
	Shares Outstanding	Redemption Price		
Cumulative preferred stock:				
$25 par value:				
4.08% Series	650,000	$ 25.50	**$ 16**	$ 25
4.24% Series	1,200,000	$ 25.80	**30**	30
4.32% Series	1,653,429	$ 28.75	**41**	41
4.78% Series	1,296,769	$ 25.80	**33**	33
Preference stock:				
No par value:				
5.349% Series A	4,000,000	$ 100.00	**400**	400
6.125% Series B	2,000,000	$ 100.00	**200**	200
6.00% Series C	2,000,000	$ 100.00	**200**	200
Total			**$ 920**	$ 929

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

Note 16. Business Segments

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

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

In millions	Electric Utility	VIEs	Eliminations	SCE
Balance Sheet Items as of December 31, 2008:				
Cash and equivalents	$ 1,522	$ 89	$ —	$ 1,611
Accounts receivable – net	679	63	(39)	703
Inventory	346	19	—	365
Other current assets	262	4	—	266
Nonutility property – net of depreciation	671	282	—	953
Other long-term assets	363	1	—	364
Total assets	**$ 32,149**	**$ 458**	**$ (39)**	**$ 32,568**
Accounts payable	926	61	(39)	948
Other current liabilities	562	2	—	564
Asset retirement obligations	2,992	15	—	3,007
Minority interest	—	380	—	380
Total liabilities and shareholders' equity	**$ 32,149**	**$ 458**	**$ (39)**	**$ 32,568**
Balance Sheet Items as of December 31, 2007:				
Cash and equivalents	$ 142	$ 110	$ —	$ 252
Accounts receivable – net	684	110	(69)	725
Inventory	265	18	—	283
Other current assets	184	4	—	188
Nonutility property – net of depreciation	700	300	—	1,000
Other long-term assets	627	2	—	629
Total assets	**$ 27,002**	**$ 544**	**$ (69)**	**$ 27,477**
Accounts payable	902	81	(69)	914
Other current liabilities	545	3	—	548
Asset retirement obligations	2,862	15	—	2,877
Minority interest	1	445	—	446
Total liabilities and shareholders' equity	**$ 27,002**	**$ 544**	**$ (69)**	**$ 27,477**

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

In millions	Electric Utility	VIEs	Eliminations[1]	SCE
Income Statement Items for the 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
Other 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 assets	(9)	—	—	(9)
Total operating expenses	**9,350**	**937**	**(692)**	**9,595**
Operating income	**1,488**	**165**	**—**	**1,653**
Interest income	19	3	—	22
Other nonoperating income	99	2	—	101
Interest expense – net of amounts capitalized	(407)	—	—	(407)
Other nonoperating deductions	(123)	—	—	(123)
Income tax expense	(342)	—	—	(342)
Minority interest	—	(170)	—	(170)
Net income	**$ 734**	**$ —**	**$ —**	**$ 734**
Income Statement Items for the Year-Ended December 31, 2007:				
Operating revenue	**$ 9,854**	**$ 1,129**	**$ (750)**	**$ 10,233**
Fuel	482	709	—	1,191
Purchased power	3,985	—	(750)	3,235
Other operation and maintenance	2,742	96	—	2,838
Depreciation, decommissioning and amortization	975	36	—	1,011
Property and other taxes	217	—	—	217
Total operating expenses	**8,401**	**841**	**(750)**	**8,492**
Operating income	**1,453**	**288**	**—**	**1,741**
Interest income	41	3	—	44
Other nonoperating income	75	14	—	89
Interest expense – net of amounts capitalized	(429)	—	—	(429)
Other nonoperating deductions	(45)	—	—	(45)
Income tax expense	(337)	—	—	(337)
Minority interest	—	(305)	—	(305)
Net income	**$ 758**	**$ —**	**$ —**	**$ 758**

In millions	Electric Utility	VIEs	Eliminations[1]	SCE
Income Statement Items for the Year-Ended December 31, 2006:				
Operating revenue	**$ 9,473**	**$ 1,137**	**$ (751)**	**$ 9,859**
Fuel	389	723	—	1,112
Purchased power	3,850	—	(751)	3,099
Other operation and maintenance	2,534	103	—	2,637
Depreciation, decommissioning and amortization	914	36	—	950
Property and other taxes	206	—	—	206
Gain on sale of assets	(1)	—	—	(1)
Total operating expenses	**7,892**	**862**	**(751)**	**8,003**
Operating income	**1,581**	**275**	**—**	**1,856**
Interest income	58	—	—	58
Other nonoperating income	85	—	—	85
Interest expense – net of amounts capitalized	(399)	—	—	(399)
Other nonoperating deductions	(60)	—	—	(60)
Income tax expense	(438)	—	—	(438)
Minority interest	—	(275)	—	(275)
Net income	**$ 827**	**$ —**	**$ —**	**$ 827**

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

Note 17. Quarterly Financial Data (Unaudited)

	2008				
In millions	Total[1]	Fourth	Third	Second	First
Operating revenue	**$ 11,248**	**$ 2,551**	**3,468**	**$ 2,850**	**$ 2,379**
Operating income	**1,653**	**316**	**663**	**331**	**345**
Net income	**734**	**154**	**248**	**170**	**163**
Net income available for common stock	**683**	**141**	**235**	**157**	**150**
Common dividends declared	**400**	**100**	**100**	**100**	**100**

	2007				
In millions	Total[1]	Fourth	Third	Second	First
Operating revenue	$ 10,233	$ 2,515	$ 3,172	$ 2,432	$ 2,115
Operating income	1,741	335	639	392	374
Net income	758	134	275	157	193
Net income available for common stock	707	120	262	144	180
Common dividends declared	100	25	25	25	25

(1) As a result of rounding, the total of the four quarters does not always equal the amount for the year.

Selected Financial Data: 2004 – 2008

Dollars in millions	2008	2007	2006	2005	2004
Income statement data:					
Operating revenue	**$ 11,248**	$ 10,233	$ 9,859	$ 9,065	$ 8,491
Operating expenses	**9,595**	8,492	8,003	7,434	6,483
Purchased-power expenses	**3,845**	3,235	3,099	2,715	2,317
Income tax expense	**342**	337	438	292	438
Interest expense – net of amounts capitalized	**407**	429	399	362	404
Net income from continuing operations	**734**	758	827	749	921
Net income	**734**	758	827	749	921
Net income available for common stock	**683**	707	776	725	915
Ratio of earnings to fixed charges	**3.41**	3.35	3.97	3.79	4.40
Balance sheet data:					
Assets	**$ 32,568**	$ 27,477	$ 26,110	$ 24,703	$ 23,290
Gross utility plant	**24,539**	22,577	20,734	19,232	17,981
Accumulated provision for depreciation and decommissioning	**5,570**	5,174	4,821	4,763	4,506
Short-term debt	**1,893**	500	—	—	88
Common shareholder's equity	**6,513**	6,228	5,447	4,930	4,521
Preferred and preference stock:					
Not subject to mandatory redemption	**920**	929	929	729	129
Subject to mandatory redemption	**—**	—	—	—	139
Long-term debt including debt due within one year	**6,362**	5,081	5,567	5,265	5,471
Capital structure:					
Common shareholder's equity	**47.2%**	50.9%	45.6%	45.1%	44.1%
Preferred stock:					
Not subject to mandatory redemption	**6.7%**	7.6%	7.8%	6.7%	1.3%
Subject to mandatory redemption	**—**	—	—	—	1.3%
Long-term debt	**46.1%**	41.5%	46.6%	48.2%	53.3%

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.

Board of Directors

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

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

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

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

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Founding Partner,
Freeman Spogli & Co.
(private investment company)
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

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

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

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

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

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

Management Team

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

John R. Fielder
President

Pedro J. Pizarro
Executive Vice President,
Power Procurement

Bruce C. Foster
Senior Vice President,
Regulatory Affairs

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

James A. Kelly
Senior Vice President,
Transmission and Distribution

Thomas M. Noonan
Senior Vice President and
Chief Financial Officer

Stephen E. Pickett
Senior Vice President and
General Counsel

Ross T. Ridenoure
Senior Vice President and
Chief Nuclear Officer

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

Lynda L. Ziegler
Senior Vice President,
Customer Service

Robert C. Boada
Vice President and Treasurer

Lisa D. Cagnolatti
Vice President,
Business Customer Division

Kevin R. Cini
Vice President,
Energy Supply and Management

Ann P. Cohn
Vice President and
Associate General Counsel

Paul J. De Martini
Vice President,
Advanced Technology

Erwin G. Furukawa
Vice President,
Customer Programs and Services

Stuart R. Hemphill
Vice President,
Renewable and Alternative Power

Harry B. Hutchison
Vice President,
Customer Service Operations

Akbar Jazayeri
Vice President,
Regulatory Operations

Walter J. Johnston
Vice President,
Power Delivery

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

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

David L. Mead
Vice President,
Engineering and Technical Services

Kevin M. Payne
Vice President,
Enterprise Resource Planning

Frank J. Quevedo
Vice President,
Equal Opportunity

Megan Scott-Kakures
Vice President and General Auditor

Michael P. Short
Vice President,
Nuclear Engineering and
Technical Services

Leslie E. Starck
Vice President,
Local Public Affairs

Kenneth S. Stewart
Vice President and
Chief Ethics and Compliance Officer

Linda G. Sullivan
Vice President and Controller

Shareholder Information

Annual Meeting

The annual meeting of shareholders will be held on Thursday, April 23, 2009, at 9:00 a.m., Pacific Time, at the Hilton Los Angeles San Gabriel Hotel, 225 West Valley Boulevard, San Gabriel, California 91776.

Corporate Governance Practices

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

Stock and Trading Information

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

Transfer Agent and Registrar

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

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

Inquiries may also be directed to:

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

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

Web Address
www.edisoninvestor.com

Online account information
www.shareowneronline.com

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