SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

2007 Annual Report

Southern California Edison Company

An Edison International (NYSE:EIX) company, Southern California Edison is the largest electric utility in California, 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
CEMA	catastrophic event memorandum account
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
District Court	U.S. District Court for the District of Columbia
DOE	United States Department of Energy
DPV2	Devers-Palo Verde II
Duke	Duke Energy Trading and Marketing, LLC
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
FIN 39-1	Financial Accounting Standards Interpretation No. 39-1, Amendment of FASB Interpretation No. 39
FIN 46(R)-6	Financial Accounting Standards Interpretation No. 46(R)-6, Determining Variability to be Considered in Applying FIN 46(R)
FIN 46(R)	Financial Accounting Standards Interpretation No. 46, Consolidation of Variable Interest Entities
FIN 47	Financial Accounting Standards 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
GHG	greenhouse gas
GRC	General Rate Case
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
Midway-Sunset	Midway-Sunset Cogeneration Company
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
NO_x	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
S&P	Standard & Poor's
SAB	Staff Accounting Bulletin
San Onofre	San Onofre Nuclear Generating Station
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. 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
SO_2	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
USEPA	United States Environmental Protection Agency
The Tribes	Navajo Nation and Hopi Tribe
VIE(s)	variable interest entity(ies)

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 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;
- access to capital markets and the cost of capital;
- changes in interest rates, rates of inflation beyond those rates which may be adjusted from year to year 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, and availability and cost of spare parts and repairs;
- the cost and availability of labor, equipment and materials;
- the ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities;
- 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 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;
- changes in the fair value of investments and other assets; 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) Liquidity; (3) Regulatory Matters; (4) Other Developments; (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

SCE management engages in a comprehensive and rigorous strategic planning process for the company to continuously identify critical success factors, current trends and industry developments affecting the company on both a long-term and short basis. In addition, annually, senior management develops the SCE goals for the upcoming year, based on this process. These goals are approved by the SCE Board of Directors.

In 2008, SCE has adopted the following goals as key to continued successful implementation of its strategic plan.

- System Reliability and Growth –
  - Achieve 2008 licensing and construction milestones for SCE's 2008 – 2012 capital investment plan.

    SCE expects to make capital investments up to $19 billion over the 2008 to 2012 period, subject to Board of Directors and other approvals, to meet system growth, ensure system reliability, replace and expand distribution and transmission infrastructure, construct and replace major components of generation assets and deploy EdisonSmartConnect™. Portions of the capital investment plan remain subject to regulatory approvals. See "Liquidity — Capital Expenditures."
- Operational Excellence –
  - Improve operational efficiency by implementing automated systems
  - Achieve key implementation milestones for SCE's Enterprise Resource Planning, advance deployment of the EdisonSmartConnect™ programs and execute the San Onofre Nuclear Generating Station business plan.

    SCE has underway an enterprise wide project, called the Enterprise Resource Planning or ERP project, to implement a comprehensive, integrated software system from SAP to support the majority of its critical business processes during the next few years. SCE expects to implement SAP financial, supply chain, human resources and certain work management modules in 2008. See "Other Developments — Enterprise-Wide Software System Project." SCE plans to deploy state-of-the-art "smart" meters to its customers over a five-year period beginning in 2008. See "Other Developments — EdisonSmartConnect™."
- Energy Resources –
  - Procure sufficient power resources consistent with the CPUC approved Procurement Plan; advocate the development of efficient and new energy supply markets; and execute vital demand-side management programs to achieve established targets.

SCE will continue to procure least-cost, best-fit power resources and execute effective hedging strategies consistent with the CPUC approved procurement plan (see "Regulatory Matters — Current Regulatory Developments — Energy Resource Recovery Account Proceedings," "— Resource Adequacy Requirements," and "— Procurement of Renewable Resources").

- Develop and promote rules to successfully implement AB 32 GHG reduction legislation, and advocate balanced plans across renewables and other GHG mitigation options. Advance potential near-zero GHG emitting power generation technology projects and explore the potential for developing additional nuclear generation. Implement corporate environmental strategies and programs.

  SCE is subject to numerous federal and state environmental 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. With respect to GHG emissions, SCE will continue to work in support of fair rules for implementing AB 32, GHG reductions and improvements to the renewable procurement standards program in California. See "Regulatory Matters — Current Regulatory Developments — Procurement of Renewable Resources," and "Other Developments — Environmental Matters."

- Financial –

  - Achieve a successful and timely resolution of the 2009 General Rate Case and an acceptable decision for the 2009 Cost of Capital Proceeding.

    SCE filed its GRC application on November 19, 2007 and expects a decision prior to year-end 2008 (see "Regulatory Matters — 2009 General Rate Case Proceeding"). In addition, SCE expects the CPUC to issue a decision on Phase II of the cost of capital proceeding in April 2008 (see "Regulatory Matters — 2008 Cost of Capital Proceeding").

In addition to meeting our financial targets and the goals discussed above,'s 2008 strategy also includes goals related to safety, operational targets, improve customer experience, increase procurement diversification, and people, values and culture, including enhancing the effectiveness of SCE's ethics and compliance programs. The SCE's 2008 goals were developed consistent with Edison International's Leading the Way in Electricity values of integrity, excellence, respect, continuous improvement and teamwork.

2007

In 2007, SCE continued effective execution of its strategic plan, with a focus on managed growth and operational excellence. Principal objectives achieved in 2007 are summarized below:

System Reliability and Growth

- Achieve milestones for SCE's capital investment plan – In 2007, SCE invested more than $2.2 billion in its continued progress to replace and expand distribution and transmission infrastructure, construct and replace major components of generation assets, including the construction of four combustion turbine peaker plants to meet summer load demand, continued development of the advanced meter project, EdisonSmartConnect[tm], and replacement of the steam generators at San Onofre which is moving forward on schedule. SCE did receive a setback in the approval process of the Devers-Palo Verde II transmission line, which will be delayed for at least two years. See "Liquidity — Capital Expenditures" and "Regulatory Matters — Current Regulatory Developments — Peaker Plant Generation Projects" and "— EdisonSmartConnect[tm]" and "— FERC Transmission Incentives" for further discussion of these matters.

Operational Excellence

- Achieve significant milestones for the Enterprise Resource Planning program – SCE has continued progress its ERP project. SCE's progress continued on preparation for the implementation of SAP financial, supply chain, human resource and certain work management modules, expected to be implemented in 2008. See "Other Developments — Enterprise-Wide Software System Project" for further discussion of this matter.
- SCE has continued to procure least-cost, best-fit power resources and execute effective hedging strategies consistent with the CPUC approved procurement plan – In 2007, SCE entered into contracts with new generation projects and reported full compliance with the Renewable Portfolio Standard goals for 2004, 2005, and 2006 and projects it will meet its renewable goals for 2007 and 2008 (see "Regulatory Matters — Current Regulatory Developments — Procurement of Renewable Resources"). The CPUC also found SCE's recorded fuel and energy expenses reasonable and SCE's contract administration, dispatch of generation resources and related spot market transactions compliant with SCE's CPUC-approved procurement plan from January 1, 2006 through December 31, 2006 and approved SCE's long-term procurement plan. In 2007, SCE took a leadership role in the development of near and long-term strategies to promote policies where SCE's bundled customers do not incur costs different than those of other load-serving entities.
- Environmental – In 2007, SCE supported state-specific measures and participated in regional legislative initiatives to reduce GHG emissions and other environmental issues. We are advancing our leading environmental work in many areas, including energy efficiency and renewables. See "Other Developments — Environmental Matters" for further discussion.

Other significant developments in 2007 included:

- A CPUC decision that adopted an Energy Efficiency Risk/Reward Incentive mechanism covering at least two three-year periods (2006 — 2008 and 2009 — 2011). The intent of the mechanism is to elevate the importance of customer energy efficiency programs by allowing utility shareholders to participate in the benefits produced by the programs, ensuring that energy efficiency is viewed as a core part of the utilities' operations. See "Regulatory Matters — Energy Efficiency Incentives" for further discussion.
- A FERC order which granted incentives for three of SCE's largest proposed transmission projects. The order grants a higher return on equity on SCE's transmission rate base in its next FERC transmission rate case and an additional increase for the Tehachapi, DPV2, and Rancho Vista projects, permits SCE to include in rate base 100% of prudently-incurred capital expenditures during the construction of all three projects and 100% recovery of prudently-incurred abandoned plant costs for DPV2 and Tehachapi, if either or both of these projects are cancelled due to factors beyond SCE's control. See "Regulatory Matters — FERC Transmission Incentives" for further discussion.
- SCE continued to strengthen its safety and ethics programs. Almost 98% of non-management employees completed ethics and compliance training in 2006 and 2007.

LIQUIDITY

Overview

As of December 31, 2007, SCE had cash and equivalents of $252 million ($110 million of which was held by SCE's consolidated VIEs). As of December 31, 2007, long-term debt, including current maturities of long-term debt, was $5.08 billion. On February 23, 2007, SCE amended its credit facility, increasing the amount of borrowing capacity to $2.5 billion, extending the maturity to February 2012 and removing the first mortgage bond security pledge. As a result of removing the first mortgage bond security, the credit facility's pricing changed to an unsecured basis per the terms of the credit facility agreement. At December 31, 2007, the credit facility supported $229 million in letters of credit and $500 million of short-term debt outstanding, leaving $1.77 billion available for liquidity purposes.

SCE's 2008 estimated cash outflows are expected to consist of:

- Projected capital expenditures of $2.8 billion primarily to replace and expand distribution and transmission infrastructure and construct and replace major components of generation assets (see "— Capital Expenditures" below);
- Dividend payments to SCE's parent company. The Board of Directors of SCE declared a $25 million dividend to Edison International which was paid in January 2008;
- Fuel and procurement-related costs (see "Regulatory Matters — Current Regulatory Developments — Energy Resource Recovery Account Proceedings"); and
- General operating expenses.

SCE expects to meet its continuing obligations, including cash outflows for operating expenses and power-procurement, through cash and equivalents on hand, operating cash flows and short-term borrowings. Projected capital expenditures are expected to be financed through operating cash flows and the issuance of short-term and long-term debt and preferred equity.

Due to recent market developments, there has been a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds have risen. Consequently, in December 2007, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and $187 million in January and February 2008. The bonds remain outstanding and have not been retired or cancelled. SCE may remarket the bonds in a term rate mode in the first half of 2008 and terminate the insurance covering the bonds. See "Market Risk Exposures" for a further discussion.

In January 2008, SCE issued $600 million of 5.95% first and 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.

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).

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 it incurs during 2008 will qualify for this accelerated bonus depreciation, which would provide additional cash flow benefits in 2008 and potentially 2009. Any cash flow benefits resulting from this accelerated depreciation should be timing in nature and therefore should result in a higher level of accumulated deferred income taxes reflected on SCE's consolidated balance sheets. Timing benefits related to deferred taxes should be incorporated into future ratemaking proceedings, impacting future period cash flow and rate base.

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

Capital Expenditures

SCE is experiencing significant growth in actual and planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. SCE's 2008 through 2012 capital investment plan which includes total capital spending of up to $19 billion is subject to approval by the Finance Committee of the Board of Directors. The 2008 planned expenditures for CPUC-jurisdictional projects are consistent with capital additions authorized by the CPUC in SCE's 2006 GRC. Recovery of the 2009 through 2011 planned expenditures is subject to CPUC approval in SCE's 2009 GRC application. The 2012 planned expenditures are subject to future approval. Recovery of certain projects included in the 2008 through 2012 investment plan has been approved or will be requested through other CPUC-authorized mechanisms on a project-by-project basis. These projects include, among others, SCE's advanced metering infrastructure project, the San Onofre steam generator replacement project, and the peaker plant generation project. SCE plans total spending for 2008 through 2012 to be $1.2 billion, $450 million, and $58 million, for each project, respectively. Recovery of the 2008 through 2012 planned expenditures for FERC-jurisdictional projects will be requested in future transmission rate filings with the FERC. The completion of the projects, the timing of expenditures, and the associated recovery may be affected by construction delays resulting from the availability of labor, equipment and materials, permitting requirements, financing, legal and regulatory developments, weather and other unforeseen conditions. During 2007, SCE spent $2.2 billion in capital expenditures related to its 2007 capital plan.

The estimated capital expenditures for the next five years are as follows: 2008 – $2.8 billion; 2009 – $3.9 billion; 2010 – $4.3 billion; 2011 – $4.4 billion; and 2012 – $3.6 billion.

Significant investments in 2008 are expected to include:

- $1.9 billion related to transmission and distribution projects;
- $313 million related to generation projects;
- $298 million related to information technology projects, including the implementation of the Enterprise Resource Planning project; and
- $277 million related to other customer service and shared services projects, including EdisonSmartConnect^{tm}.

Credit Ratings

At December 31, 2007, 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

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 set an authorized capital structure for SCE which included a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2007, SCE's 13-month weighted-average common equity component of total capitalization was 50.59% resulting in the capacity to pay $308 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, 2007, SCE's debt to total capitalization ratio was 0.44 to 1.

Margin and Collateral Deposits

SCE has entered into certain margining agreements for power and 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. At December 31, 2007, SCE had a net deposit of $266 million (consisting of $37 million in cash and reflected in "Margin and collateral deposits" on the consolidated balance sheets and $229 million in letters of credit) with counterparties and other brokers. Cash deposits with brokers and counterparties earn interest at various rates.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2007, if wholesale energy prices increase or the amount hedged increases. SCE estimates that margin and collateral requirements for energy contracts outstanding as of December 31, 2007, could increase by approximately $421 million over the remaining life of the contracts using a 95% confidence level.

The credit risk exposure from counterparties for power and gas trading activities are measured as the difference between the contract price and current fair value of open positions. 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, 2007, the amount of exposure as described above, broken down by the credit ratings of SCE's counterparties, was as follows:

In millions	**December 31, 2007**
S&P Credit Rating	
A or higher	**$ 71**
A−	**30**
BBB+	**15**
BBB	**—**
BBB−	**—**
Below investment grade	**258**
Total	**$ 374**

SCE has structured transactions (tolling contracts) in which SCE purchases all of the output of a plant from the counterparty. Accordingly, a default by a counterparty under a structured transaction, including a default as a result of a bankruptcy, would likely have a material adverse effect on SCE. In addition, SCE's structured transactions may be for multiple years which increases the volatility of the fair value position of the transaction. A number of the counterparties with which SCE has structured transactions do not currently have an investment grade rating or are below investment grade. SCE seeks to mitigate this risk through diversification of its structured transactions, when available. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from contracts.

SCE requires that counterparties with below investment grade ratings or those that do not currently have an investment grade rating post collateral. In the event of default by the counterparty, SCE would be able to use that collateral to pay for the commodity purchased or to pay the associated obligation in the event of default by the counterparty. Furthermore, all of the contracts that SCE has entered into with counterparties are entered into under SCE's short-term and long-term procurement plan which has been approved by the CPUC. As a result, SCE would qualify for regulatory recovery for any defaults by counterparties on these transactions. In addition, SCE subscribes to rating agencies and various news services in order to closely monitor any changes that may affect the counterparties' ability to perform.

In addition, as discussed in "Regulatory Matters — Overview of Ratemaking Mechanisms — CDWR-Related Rates," the CDWR entered into contracts to purchase power for the sale at cost directly to SCE's retail customers during the California energy crisis. These CDWR procurement contracts contain provisions that would allow the contracts to be assigned to SCE if certain conditions are satisfied, including having an unsecured credit rating of BBB/Baa2 or higher. However, because the value of power from these CDWR contracts is subject to market rates, such an assignment to SCE, if actually undertaken, could require SCE to post significant amounts of collateral with the contract counterparties, which could strain SCE's liquidity. In addition, the requirement to take responsibility for these ongoing fixed charges, which the credit rating agencies view as debt equivalents, could adversely affect SCE's credit rating. However, it is possible that attempts may be made to order SCE to take assignment of these contracts, and that such orders might withstand legal challenges.

SCE expects to continue its current administrative role associated with the CDWR contracts in the MRTU market and will continue to act as an agent for these transactions.

Rate Reduction Notes

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law beginning in 1998. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property was a current property right created by the restructuring legislation and a financing order of the CPUC and consisted generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes were repaid over 10 years, with the final principal payment made in December 2007, through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The nonbypassable rates being charged to customers are expected to cease at the time of SCE's next consolidated rate change which is expected to be in March 2008. All amounts collected subsequent to the final principal payment made in December 2007 will be refunded to ratepayers. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States of America, SCE Funding LLC is consolidated with SCE and the rate reduction notes were shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. As a result of the payment of the bonds, SCE Funding LLC terminated its registration on December 27, 2007 and is no longer required to file reports with the U.S. Securities and Exchange Commission.

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 customers for the sale of electricity at rates authorized by these two commissions. These rates are categorized into three groups: base rates, cost-recovery rates, and CDWR-related rates.

Base Rates

Revenue arising from base rates is 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 (or rate base). 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 GRC. In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement. After a review process and hearings, the CPUC sets an annual revenue requirement 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 annual cost of capital proceedings (as discussed below), by rate base. Adjustments to the revenue requirement for the remaining years of a typical three-year GRC cycle are requested from the CPUC based on criteria established in a GRC proceeding for escalation in operation and maintenance costs, changes in capital-related costs and the expected number of nuclear refueling outages. See "— Current Regulatory Developments — 2009 General Rate Case Proceeding" for SCE's current annual revenue requirement.

Adopted operation and maintenance costs include approval for cost inflation assumptions for principal operating costs such as labor and benefits. During the GRC cycle, cost inflation assumptions are updated by SCE, subject to CPUC approval, which mitigates the potential impact of cost inflation being materially different from the authorized levels.

Variations in generation and distribution revenue arising from the difference between forecast and actual electricity sales are recorded in balancing accounts for future recovery or refund, and do not impact SCE's operating profit. Differences between forecast and actual operating costs, other than cost-recovery costs (see below), do impact profitability.

Base rate revenue related to SCE's transmission function is authorized by the FERC in periodic proceedings that are similar to the CPUC's GRC proceeding, except that requested rate changes are generally implemented either when the application is filed or after a maximum five month suspension. Revenue collected prior to a final FERC decision is subject to refund.

SCE's capital structure, including the authorized rate of return, is regulated by the CPUC and is determined in an annual cost of capital proceeding. The rate of return is a weighted average of the return on common equity and cost of long-term debt and preferred equity. In 2007, SCE's rate-making capital structure was 48% common equity, 43% long-term debt and 9% preferred equity. SCE's authorized cost of long-term debt was 6.17%, its authorized cost of preferred equity was 6.09% and its authorized return on common equity was 11.60%. If actual costs of long-term debt or preferred equity are higher or lower than authorized, SCE's earnings are impacted in the current year and the differences are not subject to refund or recovery in rates. SCE's authorized return on common equity is 11.5% for 2008. See "— Current Regulatory Developments — 2008 Cost of Capital Proceeding" for a discussion of SCE's 2008 cost of capital proceeding.

Cost-Recovery Rates

Revenue requirements to recover SCE's costs of fuel, purchased power, demand-side management programs, nuclear decommissioning, public purpose programs, and certain operation and maintenance expenses are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 56% 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 estimated 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. SCE may request adjustments to recover or refund any under- or over-collections. The majority of costs eligible for recovery 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

On September 20, 2007, the CPUC issued a decision that adopted an Energy Efficiency Risk/Reward Incentive mechanism covering at least two three-year periods (2006 – 2008 and 2009 – 2011). On January 31, 2008, the CPUC issued a decision which made clarifying modifications to the adopted mechanism. The mechanism allows for both incentives and economic penalties based on SCE's performance toward meeting CPUC goals for energy efficiency. The intent of the mechanism is to elevate the importance of customer energy efficiency programs by allowing utility shareholders to participate in the benefits/penalties produced by such programs, ensuring that energy efficiency is viewed as a core part of the utilities' operations. Both incentives and economic penalties for each three year period are capped at $200 million. See "Regulatory Matters — Energy Efficiency Shareholder Risk/Reward Incentive Mechanism" for further discussion of SCE's 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 SCE, PG&E and SDG&E (collectively, 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 $2.3 billion was collected in 2007) are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings; however, they do impact customer rates.

Impact of Regulatory Matters on Customer Rates

SCE is concerned about high customer rates, which were a contributing factor that led to the deregulation of the electric services industry during the mid-1990s. On January 1, 2007, SCE's bundled service system average rate was 14.5¢ per-kWh (including 3.1¢ per-kWh related to CDWR which is not recognized as revenue by SCE). On 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 sales in the summer of 2006. In addition, the rate change incorporates the redesign of SCE's tiered rate structure and collection of the residential rate increase deferral. In connection with the February 14, 2007 system average change, the residential rates in the top two tiers were decreased. The residential rates at the lower tiers are capped due to AB 1X discussed below.

During the 2001 energy crisis, the California Legislature passed AB 1X which capped the rates for low-use residential customers. AB 1X fixes 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, especially following major summer heat storms. 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.

On November 27, 2007, SCE revised its 2008 ERRA forecast application, forecasting an ERRA revenue requirement of $4.03 billion, which represents an increase of $281 million over SCE's adopted 2007 ERRA revenue requirement. In addition, SCE requested to consolidate other rate changes authorized by the CPUC with this ERRA revenue requirement increase to be effective by the end of February 2008. After taking into account all other revenue requirement changes, SCE estimates that the system average rate for bundled service customers will decrease by 0.2¢ per-kWh in 2008. The bundled service system average rate will be 13.7¢ per-kWh in 2008 (including a slightly lower 2.9¢ per-kWh related to CDWR which is lower than that in effect in third quarter of 2007).

Current Regulatory Developments

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

2009 General Rate Case Proceeding

SCE filed its GRC application on November 19, 2007. The application requests a 2009 base rate revenue requirement of $5.199 billion, an increase of approximately $858 million over the projected authorized base rate revenue requirements. After considering the effects of sales growth and other offsets, SCE's request would be a $726 million increase over current authorized base rate revenue. If the CPUC approves these requested increases and allocates them to ratepayer groups on a system average percentage change basis, the percentage increases over current base rates and total rates are estimated to be 16.2% and 6.2%, respectively. The requested revenue requirement increase is necessary for SCE to build facilities to serve new customers, reinforce its system to accommodate customer load growth, replace aging infrastructure, meet regulatory requirements in generation and electricity procurement, fund increased operations and maintenance costs, and provide for increased costs to recruit, train, and retain employees in light of anticipated retirements. SCE's application also proposes a post-test year ratemaking mechanism which would result in 2010 and 2011 base rate revenue requirement increases, net of sales growth, of $216 million and $287 million, respectively, for the same reasons. SCE also requested in its application that Mountainview be included in utility rate base and its operating costs be recovered through the 2009 GRC revenue requirement rather than the current structure under which SCE recovers Mountainview generating costs through a power purchase agreement with no significant impact on rates. Several parties filed protests in December 2007, addressing various aspects of SCE's application. On February 7, 2008, a Scoping Memo was issued, which included the formal schedule and scope of issues to be addressed in the GRC. SCE cannot predict the revenue requirement the CPUC will ultimately authorize or precisely when a final decision will be adopted although a final decision is expected prior to year-end.

2008 Cost of Capital Proceeding

On December 21, 2007, the CPUC granted SCE's requested rate-making capital structure of 43% long-term debt, 9% preferred equity and 48% common equity for 2008. The CPUC also authorized SCE's 2008 cost of long-term debt of 6.22%, cost of preferred equity of 6.01% and a return on common equity of 11.5%. The impact of this Phase I decision resulted in a $7 million decrease in SCE's annual revenue requirement. In Phase II of the proceeding, the CPUC is considering whether to replace the current annual cost of capital application with a multi-year mechanism. The CPUC expects to issue a decision on Phase II in April 2008.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

On September 20, 2007, the CPUC issued a decision that adopted an Energy Efficiency Risk/Reward Incentive mechanism with subsequent modifications issued on January 31, 2008. Under this mechanism SCE has the opportunity to earn an incentive of 9% of the value of the total energy efficiency savings if it achieves between 85% and 100% of its energy efficiency goals for the cumulative three year period and can earn 12% of the value of the energy efficiency savings if 100% or greater of its goals are achieved. Economic penalties would be imposed in the event the utility achieves 65% or less of its goals. The mechanism also establishes a deadband between 65% and 85% of energy efficiency goals, where no economic penalty or incentive would be earned. The mechanism allows for collection of 65% of the first two years' (2006 – 2007) progress towards goals beginning in 2009; 65% of the next year's (2008) progress in 2010 and collection of a final true-up payment for the remaining 35%, as adjusted for actual performance in 2011. The January 2008 modifications allow the utilities to retain the first and second progress payments as long as the utilities meet a minimum of 65% of the goals, as measured by the CPUC in the third and final payment. If the utilities fall below the 65% level, the progress payment would need to be refunded and economic penalties would be incurred. Each progress payment is independently calculated based on performance to date and SCE may earn at either the 9% or 12% incentive level for each progress payment. SCE is scheduled to file advice filings in September of each year requesting recovery of the progress payments in accordance with the mechanism. SCE expects it will recognize earnings in the amount of the progress payments upon CPUC acceptance of its filing, expected in the fourth quarter of each year. SCE would record penalties at any time that it is probable that it will not meet 65% of the goals. Assuming 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. The January 2008 modifications incorporate an update to the effective useful life of the energy efficiency measures installed. If the draft CPUC effective useful life study is adopted in its current form, the effective useful life of residential compact fluorescent lights, one of the largest contributors to SCE's energy efficiency portfolio, would be reduced and SCE's earnings opportunity would decrease to approximately $124 million. Timing of progress payment claims is linked to the completion of CPUC reports. Delays in CPUC reports could cause delays in recognizing earnings for these claims. Under this mechanism, SCE is scheduled to file for expected benefits for the 2006 and 2007 timeframe in September 2008. There is no assurance of earnings in any given year. If approved by the CPUC, SCE currently projects, based on preliminary results, that it will record a progress payment in the range of $41 million to $49 million in the fourth quarter of 2008 for the first two years (2006 – 2007) of the program cycle. The final amount of the progress payment will be based on a CPUC report, scheduled to be complete in August 2008 and utilized in the September filing. SCE expects to collect this progress payment in rates in 2009. SCE estimates that it will meet 100% of its energy efficiency goals for the entire program period. In the event SCE reaches 65% or less of its goals for the 2006 – 2008 period, the approximate economic penalty could range between $58 million to $200 million for the three year period, depending on SCE's performance against its energy efficiency goals. The CPUC will review the operation of the mechanism over two three-year program periods (2006 – 2008 and 2009 – 2011) to determine if any modifications to the mechanism are warranted for the 2012 – 2014 program period.

FERC Transmission Incentives

On November 16, 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects:

- A 125 basis point ROE adder on SCE's future proposed base ROE ("ROE Adder") for Devers-Palo Verde II ("DPV2"), which is a high voltage (500 kV) transmission line from the Valley substation to the Devers substation near Palm Springs, California to a new substation near Palo Verde, west of Phoenix, Arizona;
- A 125 basis point ROE Adder for the Tehachapi Transmission Project ("Tehachapi"), which is an eleven segment project consisting of newly-constructed and upgraded transmission lines and associated substations to interconnect renewable generation projects near the Tehachapi and Big Creek area; and
- A 75 basis point ROE Adder for the Rancho Vista Substation Project ("Rancho Vista"), which is a new 500 kV substation in the City of Rancho Cucamonga.

The order also grants a higher return on equity on SCE's entire transmission rate base in SCE's next FERC transmission rate case for SCE's participation in the CAISO. SCE has not yet determined when it expects to file its next FERC rate case. In addition, the order 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 DPV2 and Tehachapi, if either or both of these projects are cancelled due to factors beyond SCE's control.

The Tehachapi and Rancho Vista projects are proceeding as anticipated. However, despite SCE having obtained approvals for the DPV2 project from the CPUC and other Arizona governmental agencies, by a decision dated June 6, 2007 the Arizona Corporation Commission (ACC) denied approval of the DPV2 project. SCE filed an appeal of the ACC's decision with the Maricopa County Superior Court on August 31, 2007 and agreed to a stay of the appeal until March 2008 in order to allow it to explore potential options with the Arizona stakeholders, including the ACC. SCE 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 ACC denial has resulted in a minimum two-year delay of the DPV2 project. For the period January 2003 to December 31, 2007, SCE has spent approximately $31 million on this project. SCE expects to fully recover its costs from this project, but cannot predict the outcome of regulatory proceedings.

FERC Construction Work in Progress Mechanism

On December 21, 2007, SCE filed a revision to its Transmission Owner Tariff to collect 100% of CWIP in rate base for Tehachapi, DPV2, and Rancho Vista, as authorized by FERC in its transmission incentives order discussed above. In the CWIP filing, SCE proposed a single-issue rate adjustment ($45 million or a 14.4% increase) to SCE's currently authorized base transmission revenue requirement to be made effective on March 1, 2008 and later adjusted for amounts actually spent in 2008 through a new balancing account mechanism. The rate adjustment represents actual expenditures from September 1, 2005 through November 30, 2007, projected expenditures from December 1, 2007 through December 31, 2008, and a return on equity (which includes the return on equity adders approved for Tehachapi, DPV2 and Rancho Vista). SCE projects that it will spend a total of approximately $244 million, $27 million, and $181 million for Tehachapi, DPV2, and Rancho Vista, respectively, from September 1, 2005 through the end of 2008. The 2008 DPV2 expenditure forecast is limited to projected consulting and legal costs associated with SCE's continued efforts to obtain regulatory approvals necessary to construct the DPV2 Project. If the CWIP filing is approved, the resulting incremental CWIP revenue requirement will be added to the existing base transmission revenue requirement. FERC is expected to issue a decision on the CWIP filing by February 29, 2008.

Energy Resource Recovery Account Proceedings

The ERRA is the balancing account mechanism to track and recover SCE's fuel and procurement-related costs. As described in "— Overview of Ratemaking Mechanisms," SCE recovers these costs on a cost-recovery basis, with no mark-up for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. These costs are tracked and recovered in customer rates through the ERRA, as incurred, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA balancing account incurs an overcollection or undercollection in excess of 4% of SCE's prior year's generation revenue (base generation and procurement costs), the CPUC has established a "trigger" mechanism, whereby SCE must file an application in which it can request an emergency rate adjustment if the ERRA overcollection or undercollection exceeds 5% of SCE's prior year's generation revenue.

At December 31, 2007, the ERRA was overcollected by $433 million, which was 6.32% of SCE's prior year's generation revenue. On November 27, 2007, SCE notified the CPUC that the 2007 ERRA overcollection exceeded 5% of SCE's generation revenue from the prior year and proposed to include the refund of the ERRA over-collection in the planned consolidated rate change on January 1, 2008 or soon thereafter. As discussed above in "— Impact of Regulatory Matters on Customer Rates," SCE expects a final CPUC decision in mid-March and will begin to refund the over-collection to customers in early April 2008.

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.

Effective February 16, 2006, SCE was required to demonstrate that it had procured sufficient resources to meet 90% of its June – September 2006 system resource adequacy requirement. Beginning in May 2006, 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). For years after 2006, SCE is required to make its year-ahead system resource adequacy showing (90% threshold) in the fall of the calendar year prior to the compliance year. SCE made a showing of compliance with its system resource adequacy requirements in each of its monthly compliance filings for each month in 2007. SCE made a showing of compliance with its year-ahead system resource adequacy requirements for 2007 and 2008 in November 2006 and October 2007, respectively. SCE expects to make a showing of compliance with its system resource adequacy requirements in each of its month-ahead system resource adequacy compliance filings for 2008. 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 made a showing of compliance with its local resource adequacy requirements for 2007 and 2008 in November 2006 and October 2007, respectively.

The resource adequacy compliance filings are subject to approval by the CPUC. SCE expects to be in full compliance 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 construction of five combustion turbine peaker plants. In August 2007, four of these peaker plants were placed online and all four units have been dispatched to help meet peak customer demands and other system requirements. SCE continues to pursue the construction of the fifth project, but the required development permit has been denied by the City of Oxnard. SCE has appealed this denial to the Coastal Commission and expects a decision in the first half of 2008. SCE cannot predict the outcome of the proceeding nor estimate the impact of a delayed permit issuance on the project's construction schedule. In December 2007, pursuant to the CPUC's August 2006 ruling, SCE filed an application with the CPUC for recovery of $238 million of capital costs of acquiring and installing the four installed peakers recorded as of November 30, 2007, and projecting $24 million of additional construction-related capital expenditures. SCE proposes recovery of the latter amount through SCE's 2009 ERRA proceeding. Although the fifth peaker has not yet been permitted and installed it has been largely engineered and fabricated and as of December 31, 2007, SCE has incurred capital costs of approximately $36 million for that peaker. In the application SCE proposes to continue tracking the capital costs of the fifth peaker according to the interim cost tracking mechanism that was previously approved by the CPUC for all five peaker projects while they were in construction, and SCE proposes to file a separate cost recovery application for the fifth peaker after it is installed or its final disposition is otherwise determined. SCE believes it will be able to site the fifth peaker at another location, sell the peaker, or utilize it for spare parts if there is an unfavorable permitting outcome. SCE expects to fully recover its costs from these projects, but cannot predict the outcome of regulatory proceedings. SCE expects a CPUC decision on its December 2007 application in the second half of 2008.

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.

In March 2007, SCE successfully challenged the CPUC's calculation of SCE's annual targets. This change is expected to enable SCE to meet its target for 2007. On April 3, 2007, SCE filed its renewable portfolio standard compliance report for 2004 through 2006. The compliance report confirms that SCE met its renewable goals for each of these years. In light of the annual target revisions that resulted from the March 2007 successful challenge to the CPUC's calculation, the report also projects that SCE will meet its renewable goals for 2007 and 2008 but could have a potential deficit in 2009. The potential deficit in 2009, however, does not take into account future procurement opportunities or the full utilization by SCE of the CPUC's rules for flexible compliance with annual targets. 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.

SCE is scheduled to update the compliance report discussed above in March 2008, and currently anticipates demonstrating full compliance for the procurement year 2007 as well as forecasting full compliance, with the use of flexible compliance rules, for the procurement year 2008. 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 failure 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 failing to achieve renewable procurement targets is $25 million per year. SCE cannot predict whether it will be assessed penalties.

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 has 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.

On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE's decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE's customers. The other Mohave co-owners subsequently made similar announcements. 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 "as is" to a power plant operator, decommissioning and sale of the property to a developer, decommissioning and apportionment of the land among the owners, or developing renewable energy production.

Following the suspension of Mohave operations at the end of 2005, the plant's workforce was reduced from over 300 employees to 37 employees by the end of 2007. SCE recorded $5 million in termination costs during the year for Mohave (SCE's share). These termination costs were deferred in a balancing account authorized in the 2006 GRC decision. SCE expects to recover this amount in the balancing account in future rate-making proceedings.

As of December 31, 2007, SCE had a Mohave net regulatory asset of approximately $68 million representing its net unamortized coal plant investment, partially offset by revenue collected for future removal costs. Based on the 2006 GRC 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, during the three-year 2006 rate case cycle. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave, pursuant to a California statute requiring such notice to the CPUC whenever a plant has been out of service for nine consecutive months. SCE also reported to the CPUC on Mohave's status numerous times previously. Pursuant to the statute, 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. In the past, the CPUC has allowed full recovery of investment for similarly situated plants. However, in a December 2004 decision, the CPUC noted that SCE would not be allowed to recover any unamortized plant balances if SCE could not demonstrate that it took all steps to preserve the "Mohave-open" alternative. SCE believes that it will be able to demonstrate that SCE did everything reasonably possible to return Mohave to service, which it further believes would permit its unamortized costs to be recovered in future rates. 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 order reversed an arbitrator's award that had affirmed the ISO's characterization in May 2000 of the charges as Intra-Zonal Congestion costs and allocation of those charges to scheduling coordinators in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from scheduling coordinators in the affected zone to the responsible participating transmission owner, SCE. The potential cost to SCE, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the time, is estimated to be approximately $20 million to $25 million, including interest. On April 20, 2005, the FERC stayed its April 20, 2004 order during the pendency of SCE's appeal filed with the Court of Appeals for the D.C. Circuit. On March 7, 2006, the Court of Appeals remanded the case back to the FERC at the FERC's request and with SCE's consent. On March 29, 2007, the FERC issued an order agreeing with SCE's position that the charges incurred by the ISO were related to voltage support and should be allocated to the scheduling coordinators, rather than to SCE as a transmission owner. The Cities filed a request for rehearing of the FERC's order on April 27, 2007. On May 25, 2007, the FERC issued a procedural order granting the rehearing application for the limited purpose of allowing the FERC to give it further consideration. In a future order, FERC may deny the rehearing request or grant the requested relief in whole or in part. SCE believes that the most recent substantive FERC order 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.

Scheduling Coordinator Tariff Dispute

Pursuant to the Amended and Restated Exchange Agreement, SCE serves as a scheduling coordinator for the DWP over the ISO-controlled grid. In late 2003, SCE began charging the DWP under a tariff subject to refund for FERC-authorized scheduling coordinator and line loss charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges had been billed to the DWP under a FERC tariff that was subject to dispute. The DWP has paid the amounts billed under protest but requested that the FERC declare that SCE was obligated to serve as the DWP's scheduling coordinator without charge. The FERC accepted SCE's tariff for filing, but held that the rates charged to the DWP have not been shown to be just and reasonable and thus made them subject to refund and further review by the FERC.

In January 2008, an agreement between SCE and the DWP was executed settling the dispute discussed above. The settlement had been previously approved by the FERC in July 2007. The settlement agreement provides that the DWP will be responsible for line losses and SCE would be responsible for the scheduling coordinator charges. During the fourth quarter of 2007, SCE reversed and recognized in earnings (under the caption "Purchased power" in the consolidated statements of income) $30 million of an accrued liability representing line losses previously collected from the DWP that were subject to refund. As of December 31, 2007, SCE had an accrued liability of approximately $22 million (including $3 million of interest) representing the estimated amount SCE will refund for scheduling coordinator charges previously collected from the DWP. SCE made its first refund payment on February 20, 2008 and the second refund payment is due on March 15, 2008. SCE previously received FERC-approval to recover the scheduling coordinator charges from all transmission grid customers through SCE's transmission rates and on December 11, 2007 the FERC accepted SCE's proposed transmission rates reflecting the forecast levels of costs associated with the settlement. Upon signing of the agreement in January 2008, SCE recorded a regulatory asset and recognized in earnings the amount of scheduling coordinator charges to be collected through rates.

FERC Refund Proceedings

SCE is participating in several related proceedings seeking recovery of refunds 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, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

On August 2, 2006, the Ninth Circuit issued an opinion regarding the scope of refunds issued by the FERC. The Ninth Circuit broadened the time period during which refunds could be ordered to include the summer of 2000 based on evidence of pervasive tariff violations and broadened the categories of transactions that could be subject to refund. As a result of this decision, SCE may be able to recover additional refunds from sellers of electricity during the crisis with whom settlements have not been reached.

During the course of the refund proceedings, the FERC ruled that governmental power sellers, like private generators and marketers that sold into the California market, should refund the excessive prices they received during the crisis period. However, in late 2005, the Ninth Circuit ruled in Bonneville Power Admin v. FERC that the FERC does not have authority directly to enforce its refund orders against governmental power sellers. The Court, however, clarified that its decision does not preclude SCE or other parties from pursuing civil claims or refunds against the governmental power sellers.

In March 2007, SCE, PG&E and the Oversight Board filed claims in the U.S. Court of Federal Claims against two federal agencies that sold power into California during the energy crisis. On February 7, 2008, the federal agencies filed a motion to dismiss the case. The Court's ruling on the motion is expected in the second half of 2008. In April 2007, SCE, along with PG&E, the Oversight Board and SDG&E, filed claims for refunds against several non-federal governmental power sellers in the Los Angeles Superior Court.

In October 2007, the FERC issued an order on remand from the Ninth Circuit's Bonneville decision, in which it concluded that the decision required the FERC to vacate its previous orders compelling governmental sellers during the California energy crisis to pay refunds. Based on this conclusion, the FERC also ordered the release of the amounts that had been withheld from governmental sellers as well as any collateral posted by the sellers for power delivered by them during the energy crisis. In its order, the FERC also expressly recognized that civil lawsuits against the governmental sellers could provide an alternative refund remedy for SCE and the other California utilities. It also left open the possibility that a court could order the ISO or PX to retain collateral. SCE cannot predict at this time the ultimate impact of the FERC's orders on SCE's ability to recover refunds from governmental power sellers through the pending lawsuits.

In November 2005, SCE and other parties entered into a settlement agreement with Enron Corporation and a number of its affiliates, most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In 2006 and 2007, SCE received distributions of approximately $55 million and $24 million, respectively, on its allowed bankruptcy claim. Additional distributions are expected but SCE cannot currently predict the amount or timing of such distributions.

Investigations Regarding Performance Incentives Rewards

SCE was eligible under its CPUC-approved PBR mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability. SCE conducted investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million over the period 1997 – 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of approximately $10 million for 2003.

Following its internal investigation, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forgo an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997 – 2003). In addition, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading.

SCE has taken remedial action as to the customer satisfaction survey misconduct by disciplining employees and/or terminating certain employees, including several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 GRC.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE conducted an investigation into the accuracy of SCE's employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has recognized $20 million in employee safety incentives for 1997 through 2000 and, based on SCE's records, may be entitled to an additional $15 million for 2001 through 2003.

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. SCE disclosed in the investigative findings to the CPUC that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism and return to ratepayers the $20 million it has already received. SCE has also proposed to withdraw the pending rewards for the 2001 – 2003 time frames.

SCE has taken remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance, disciplining employees who committed wrongdoing and terminating one employee. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE conducted an investigation into the third PBR metric, system reliability for the years 1997 – 2003. SCE received $8 million in reliability incentive awards for the period 1997 – 2000 and applied for a reward of $5 million for 2001. For 2002, SCE's data indicated that it earned no reward and incurred no penalty. For 2003, based on the application of the PBR mechanism, it would incur a penalty of $3 million and accrued a charge for that amount in 2004. On February 28, 2005, SCE provided its final investigation report to the CPUC concluding that the reliability reporting system was working as intended.

CPUC Investigation

On June 15, 2006, the CPUC instituted a formal investigation to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, employee safety and system reliability portions of PBR. In June 2006, the CPSD of the CPUC issued its report regarding SCE's PBR program, recommending that the CPUC impose various refunds and penalties on SCE. Subsequently, in September 2006, the CPSD and other intervenors, such as the CPUC's DRA and The Utility Reform Network, filed testimony on these matters recommending various refunds and penalties be imposed on SCE. In their testimony, the various parties made refund and penalty recommendations that range up to the following amounts: refund or forgo $48 million in rewards for customer satisfaction, impose $70 million penalties for customer satisfaction, refund or forgo $35 million in rewards for employee safety, impose $35 million penalties for employee safety, impose $102 million in statutory penalties, refund $84 million related to amounts collected in rates for employee bonuses ("results sharing"), refund $4 million of miscellaneous survey expenses, and require $10 million of new employee safety programs. These recommendations total up to $388 million. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors.

On October 1, 2007, a POD was released ordering SCE to refund $136 million, before interest, and pay a statutory penalty of $40 million. Included in the amount to be refunded are $28 million related to customer satisfaction rewards, $20 million related to employee safety rewards, and $77 million related to results sharing. The decision requires that the proposed results sharing refund of $77 million (based on year 2000 data) be adjusted for attrition and escalation which increases the results sharing refund to $88 million. Interest as of December 31, 2007, based on amounts collected for customer satisfaction, employee safety incentives and results sharing, including escalation and attrition adjustments, would add an additional $28 million to this amount. The POD also requires SCE to forgo $35 million in rewards for which it would have otherwise been eligible. Included in the amount to be forgone is $20 million related to customer satisfaction rewards and $15 million related to employee safety rewards.

On October 31, 2007, SCE appealed the POD to the CPUC. The CPSD and an intervenor also filed appeals. The CPSD appeal requested that: (1) the statutory penalty be increased from $40 million to $83 million (2) a penalty be imposed under the PBR customer satisfaction and employee safety mechanisms in the amount of $48 million and $35 million, respectively, and (3) SCE refund/forgo rewards earned under the customer satisfaction and employee safety mechanisms of $48 million and $35 million, respectively. The appealing intervenor asked that the statutory penalty be increased to as much as $102 million. Oral argument on the appeals took place on January 30, 2008, and it is uncertain when the CPUC will issue a decision.

SCE cannot predict the outcome of the appeal. Based on SCE's proposed refunds, the combined recommendations of the CPSD and other intervenors, as well as the POD, the potential refunds and penalties could range from $52 million up to $388 million. SCE has recorded an accrual at the lower end of this range of potential loss and is accruing interest (approximately $16 million as of December 31, 2007) on collected amounts.

The system reliability component of PBR was not addressed in the POD. Pursuant to an earlier order in the case, system reliability incentives will be addressed in a second phase of the proceeding, which commenced with the filing of SCE's opening testimony in September 2007. In that testimony, SCE confirmed that its PBR system reliability results, which reflected rewards of $13 million for 1997 through 2002 and a penalty of $3 million in 2003 were valid. An indefinite suspension of the schedule for the second phase of the proceeding pending resolution of the appeals of the POD has been granted. SCE cannot predict the outcome of the second phase.

Market Redesign Technical 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 redesigned California energy market under the MRTU is expected to include the following new features, among others, which are not part of the current ISO real-time only market:

- An integrated forward market for energy, ancillary services and congestion management that operates on a day-ahead basis;
- Congestion management that represents all network transmission constraints;

- CRRs to allow market participants to manage their costs of transmission congestion (see "Market Risk Exposures — Commodity Price Risk" for further discussion);
- Local energy prices by price nodes (approximately 3,000 nodes in total), also known as locational marginal pricing; and
- New market rules and penalties to prevent gaming and illegal manipulation of the market as well as modifications to certain existing market rules.

The MRTU was scheduled for implementation on March 31, 2008 and has been delayed to the fall of 2008. No new implementation date has been announced. Power will be scheduled on a nodal basis, rather than the current zonal system, which will aid in grid reliability and congestion management. Furthermore, the MRTU will incorporate the CPUC's resource adequacy requirements to ensure that there are adequate energy resources in critical areas. The MRTU will not affect how costs are recovered through rates. SCE continues to work with the ISO to develop the MRTU.

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 it is 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 results of operations or financial position.

SCE's projected environmental capital expenditures over the next five years are: 2008 – $447 million; 2009 – $444 million; 2010 – $487 million; 2011 – $491 million; and 2012 – $532 million. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines.

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 the operations of SCE. 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.

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.

Litigation Developments

Significant climate change litigation, raising issues that may affect the timing and scope of future GHG emission regulation, has been brought by a variety of public and private parties in the past several years. Although decisions were handed down in several of the major cases in 2007, it is too early to determine how the courts will respond to every situation. To date, the cases in which plaintiffs have sought damages or equitable relief directly from power companies and other defendants have been dismissed, either because the courts have 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 caused by climate change. For example, Connecticut v. AEP, a case brought in 2004 by several states and environmental organizations alleging that several electric utility corporations are jointly and severally liable under a theory of public nuisance for power plants owed and operated by these companies or their subsidiaries, was dismissed and is currently on appeal before the United States Court of Appeals for the Second Circuit. In another case brought in April 2006, private citizens filed a complaint in federal court in Mississippi against numerous defendants, including Edison International 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 July 2006, Edison International was dismissed from the case due to its status as a holding company. In August 2007, the court dismissed the case entirely. The plaintiffs have appealed this dismissal in the Fifth Circuit Court of Appeals. On the other hand, plaintiffs thus far have been generally successful in cases in which they have sought to compel federal or state agencies to regulate GHG emissions.

Responses to Energy Demands and Future GHG Emission Constraints

Irrespective of the outcome of federal legislative deliberations, SCE believes that substantial limitations on GHG emissions are inevitable, through increased costs, mandatory emission limits or other mechanisms, and that demand for energy from renewable sources will also continue to increase. As a result, SCE is utilizing its experience in developing and managing a variety of energy generation systems to create a generation profile, using sources such as wind, solar, geothermal, biomass and small hydro plants, that will be adaptable to a variety of regulatory and energy use environments. SCE leads the nation in renewable power delivery. Its renewable portfolio currently consists of: 1,021 MW from wind, 892 MW from geothermal, 354 MW from solar, 221 MW from biomass, 128 MW from SCE-owned small hydro (six of the 36 hydroelectric projects that SCE currently operates have generated power for more than a century), and 95 MW from independently owned small hydro.

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

State Specific Legislative Initiatives

SCE is evaluating the CARB's reporting regulations adopted in December 2007 pursuant to AB 32 to assess the total cost of compliance. On February 8, 2008, the CPUC and CEC recommended, in a proposed decision, that CARB adopt a mix of direct mandatory/regulatory requirements and a cap-and-trade system for the energy sectors. The proposed decision's requirements include: all retail electricity providers should be required to provide all cost-effective energy efficiency programs and renewable energy delivery beyond the level of 20% of their retail sales to their customers; a multi-sector cap-and-trade program should be developed for California that includes the electricity sector; the CARB should designate deliverers of electricity to the California grid as the entities responsible for compliance with the AB 32 requirements; at least some portion of the emission allowances available to the electricity sector for the cap-and-trade program should be auctioned. An integral part of this auction recommendation is that at least a portion of the proceeds from the auctioning of allowances for the electricity sector should be used in ways that benefit electricity consumers in California, such as to augment investments in energy efficiency and renewable energy or to provide customer bill relief. SCE is currently evaluating the proposed decision.

Other California legislative proposals or initiatives addressing climate change, including requirements for procurement of power from renewable resources, if adopted, could have a material impact on SCE's business.

Water Quality Regulation

Clean Water Act — Cooling Water Intake Structures

The California State Water Resources Control Board is currently developing a draft state policy on ocean-based, once-through cooling in advance of the issuance of a final rule from the US EPA on Section 316(b) of the Clean Water Act. 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. Portions of the draft policy revealed by Board staff members in January 2008 suggest that the policy will show retrofitting existing plants with cooling towers as the best technology available for reducing detrimental effects on marine organisms as a result of once-through cooling. Additionally, target levels for compliance with the state policy will likely be at the high end of the ranges originally proposed in the US EPA's rule. Board members have commented publicly that a policy will be released by mid 2008 with workshops and public hearings to follow later in the year. Until the release of the draft policy, SCE is unable to predict its effect on SCE operations accurately, but it could result in significant additional capital expenditures and/or procurement costs.

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, 2007, SCE's recorded estimated minimum liability to remediate its 24 identified sites was $66 million, of which $31 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 $147 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 $34 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $64 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 $25 million, $14 million and $13 million for 2007, 2006 and 2005, 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.

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 conducted during 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 which is expected to begin in 2008 and be completed 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, 2007 is $407 million. SCE expects to recover the remaining book value of the existing meters over their remaining lives through its 2009 GRC application.

On July 26, 2007, the CPUC approved $45 million for Phase II of this project. The Phase II work was completed in December 2007. SCE filed its Phase III application on July 31, 2007, requesting CPUC authorization to deploy EdisonSmartConnect^{tm} meters. SCE expects a decision on the Phase III application by August 2008.

Enterprise-Wide Software System Project

SCE continued progress during 2007 on preparation for the installation of the Enterprise Resource Planning system from SAP. SCE expects to implement financial, supply chain, human resource and certain work management modules in 2008.

Federal and State Income Taxes

Tax Positions being addressed as part of active examinations and administrative appeals processes

Edison International and its subsidiaries remain subject to examination and administrative appeals by the IRS for tax years 1994 and forward. Edison International is challenging certain IRS deficiency adjustments for tax years 1994 – 1999 with the Administrative Appeals branch of the IRS and Edison International is currently under active IRS examination for tax years 2000 – 2002. 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 years.

In the examination phase for tax years 1994 – 1999, which is complete, the IRS asserted income tax deficiencies related to certain tax positions taken by Edison International on filed tax returns. Edison International is challenging the asserted tax deficiencies in IRS Appeals proceedings; however, most of the tax positions are timing differences and, therefore, any amounts that would be paid if Edison International's position is not sustained (exclusive of any penalties) would be deductible on future tax returns filed by Edison International. In addition, Edison International has filed affirmative claims with respect to certain tax years from 1986 through 2005 with the IRS and state tax authorities. Any benefits associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when SCE makes an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is consummated. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

In April 2007, Edison International received a Notice of Proposed Adjustment from the California Franchise Tax Board for tax years 2001 and 2002 and is currently protesting the deficiencies asserted. Edison International remains subject to examination by the California Franchise Tax Board for tax years 2003 and forward. Edison International is also subject to examination by other state tax authorities, with varying statute of limitations.

Balancing Account Over-Collections

In response to an affirmative claim related to balancing account over-collections, Edison International received an IRS Notice of Proposed Adjustment in July 2007. This affirmative claim is part of the ongoing IRS examinations and administrative appeals process and all of the tax years included in this Notice of Proposed Adjustment remain subject to ongoing examination and administrative appeals. The cash and earnings impacts of this position are dependent on the ultimate settlement of all open tax issues in these tax years. SCE expects that resolution of this particular issue could potentially increase earnings and cash flow within the range of $70 million to $80 million and $300 million to $325 million, respectively.

Contingent Liability Company

The IRS has asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company for tax years 1997 – 1998. This is being considered by the Administrative Appeals branch of the IRS where Edison International is defending its tax return position with respect to this transaction.

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.

Resolution of Federal and State Income Tax Issues Being Addressed in Ongoing Examinations and Administrative Appeals

In 2008, Edison International will continue its efforts to resolve open tax issues through tax year 2002. 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.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in Midway-Sunset, which owns a 225 MW cogeneration facility near Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC because Midway-Sunset was a seller in the PX market during 2000 and 2001, both for its own account and on behalf of SCE and PG&E, the utilities to which the majority of Midway-Sunset's power was contracted for sale. As a seller into the PX market, Midway-Sunset is potentially liable for refunds to purchasers in these markets.

The claims asserted against Midway-Sunset for refunds related to power sold into the PX market, including power sold on behalf of SCE and PG&E, are estimated to be less than $70 million for all periods under consideration. Midway-Sunset did not retain any proceeds from power sold into the PX market on behalf of SCE and PG&E in excess of the amounts to which it was entitled under the pre-existing power sales contracts, but instead passed through those proceeds to the utilities. Since the proceeds were passed through to the utilities, EME believes that PG&E and SCE are obligated to reimburse Midway-Sunset for any refund liability that it incurs as a result of sales made into the PX market on their behalves.

On December 20, 2007, Midway-Sunset entered into a settlement agreement with SCE, PG&E, SDG&E and certain California state parties to resolve Midway-Sunset's liability in the FERC refund proceedings. Midway-Sunset concurrently entered into a separate agreement with SCE and PG&E that provides for pro-rata reimbursement to Midway-Sunset by the two utilities of the portions of the agreed to refunds that are attributable to sales made by Midway-Sunset for the benefit of the utilities. The settlement has been approved by the CPUC but remains subject to approval by the FERC.

During the period in which Midway-Sunset's generation was sold into the PX market, amounts SCE received from Midway-Sunset for its pro-rata share of such sales were credited to SCE's customers against power purchase expenses through the ratemaking mechanism in place at that time. SCE believes that any net amounts reimbursed to Midway-Sunset would be recoverable from its customers through current regulatory mechanisms. SCE does not expect any reimbursement to Midway-Sunset to have a material impact on earnings.

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.

In April 2004, the District Court denied SCE's motion for summary judgment and concluded that a 2003 U.S. Supreme Court decision in an on-going related lawsuit by the Navajo Nation against the U.S. Government did not preclude the Navajo Nation from pursuing its RICO and intentional tort claims. In September 2007, the Federal Circuit reversed a lower court decision on remand in the related lawsuit, finding that the U.S. Government had breached its trust obligation in connection with the setting of the royalty rate for the coal supplied to Mohave. Subsequently, the Federal Circuit denied the U.S. Government's petition for rehearing. The U.S. Government may, however, still seek review by the Supreme Court of the Federal Circuit's September decision.

Pursuant to a joint request of the parties, the District Court granted a stay of the action in October 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. In a joint status report filed on November 9, 2007, the parties informed the court that their mediation efforts had terminated and subsequently filed a joint motion to lift the stay. The parties have also filed recommendations for a scheduling order to govern the anticipated resumption of litigation. The Court has not yet ruled on either the motion to lift the stay or the scheduling recommendations, but has scheduled a status hearing for March 6, 2008. SCE cannot predict the outcome of the Navajo Nation's and Hopi Tribe's complaints against SCE or the ultimate impact on these complaints of the Supreme Court's 2003 decision and 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 $10.8 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. The current maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than $15 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 will be adjusted for inflation on a 5-year schedule. The next inflation adjustment will occur no later than August 20, 2008. Based on its ownership interests, SCE could be required to pay a maximum of $201 million per nuclear incident. However, it would have to pay no more than $30 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 regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

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 $46 million per year. Insurance premiums are charged to operating expense.

Palo Verde Nuclear Generating Station Inspection

The NRC held three special inspections of Palo Verde, between March 2005 and February 2007. A follow-up to the first inspection resulted in a finding that Palo Verde had not established adequate measures to ensure that certain corrective actions were effective to address the reduction in the ability to cool water before returning it to the plant. The second inspection identified five violations, but none of those resulted in increased NRC scrutiny. The third inspection, concerning the failure of an emergency backup generator at Palo Verde Unit 3 identified a violation that, combined with the first inspection finding, will cause the NRC to undertake additional oversight inspections of Palo Verde. In addition, Palo Verde will be 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. These corrective actions are currently being developed in conjunction with the NRC, and are forecast to be completed and embodied in an NRC Confirmatory Order by the end of February 2008. These corrective actions will increase costs to both Palo Verde and its co-owners, including SCE. SCE cannot calculate the total increase in costs until the corrective actions are finalized and the NRC issues the Confirmatory Order. The operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE presently estimates that operation and maintenance costs will increase by approximately $23 million (nominal) over the two year period 2008 – 2009, from 2007 recorded costs including overhead costs. SCE also is unable to estimate how long SCE will continue to incur these costs.

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 obligation to begin acceptance of spent nuclear fuel not later than 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 through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the 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. The case was stayed through April 7, 2006, when SCE and the DOE filed a Joint Status Report in which SCE sought to lift the stay and the government opposed lifting the stay. On June 5, 2006, the Court of Federal Claims lifted the stay on SCE's case and established a discovery schedule. A Joint Status Report was filed on February 22, 2008, regarding further proceedings in this case and presumably including establishing a trial date.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation where all of Unit 1's spent fuel located at San Onofre and some of Unit 2's spent fuel is stored. SCE, as operating agent, plans to transfer fuel from the Unit 2 and 3 spent fuel pools to the independent storage installation on an as-needed basis to maintain full core off-load capability for Units 2 and 3. There are now sufficient dry casks and modules available at the independent spent fuel storage installation to meet plant requirements through 2008. SCE plans to add storage capacity incrementally to meet the plant requirements until 2022 (the end of the current NRC operating license).

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed an independent spent fuel storage facility. Arizona Public Service, as operating agent, plans to add storage capacity incrementally to maintain full core off-load capability for all three units.

Subprime U.S. Credit Market

Due to recent market developments, including a series of rating agency downgrades of subprime U.S. mortgage-related assets, the fair value of subprime-related investments have declined. SCE has performed an assessment of its investments held in trusts related to its pension and postretirement benefits other than pensions, nuclear decommissioning obligations, and investments in cash. SCE does not believe a decline in the fair value of the subprime-related investments will have a material impact on its trust assets or its investments in cash.

As of December 31, 2007, SCE had $977 million of tax-exempt and taxable pollution control bonds insured by AAA-rated bond insurers, namely Financial Guaranty Insurance Company (FGIC), MBIA Insurance Corporation (MBIA) and XL Capital Assurance Inc. (XL). Due to the exposure that these bond insurers have in connection with recent developments in the subprime credit market, the rating agencies have put these insurers on review for possible downgrade. Additionally, Fitch and Standard & Poor's have lowered FGIC's credit ratings from AAA to AA; and Moody's lowered FGIC's credit ratings from Aaa to A3. Fitch and Moody's have lowered XL's credit ratings from AAA and Aaa to A and A3, respectively. Holders of the above mentioned insured SCE bonds have no ratings-related put rights and SCE expects these obligations to remain outstanding until contractual maturity with no change in financing terms and conditions.

However, the interest rates on one issue of SCE's taxable pollution control bonds insured by FGIC, totaling $249 million, are reset every 35 days through an auction process. Due to a loss of confidence in the creditworthiness of the bond insurers, there has been a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds have risen. Consequently, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and $187 million in January and February 2008. The bonds remain outstanding and have not been retired or cancelled. The instruments under which the bonds were issued allow SCE to convert the bonds to other short-term variable-rate, term rate or fixed-rate modes. SCE may remarket the bonds in a term rate mode in the first half of 2008 and terminate the insurance covering the bonds.

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 2008 and 11.6% for 2007 and 2006), which is established in SCE's annual cost of capital proceeding, is set on the basis of forecasts of interest rates and other factors.

At December 31, 2007, 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, 2007, the fair market value of SCE's long-term debt was $5.10 billion, compared to a carrying value of $5.08 billion. A 10% increase in market interest rates would have resulted in a $287 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 $318 million increase in the fair market value of SCE's long-term debt.

Commodity Price Risk

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 purchases power from QFs under CPUC-mandated contracts. 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.

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.

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, and forward physical contracts. In the first quarter of 2007 SCE secured FTRs through the annual ISO auction. These FTRs provide SCE with scheduling priority in certain transmission grid congestion areas in the day-ahead market and qualify as derivative instruments. 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. Certain derivative instruments do not meet the normal purchases and sales exception because demand variations and CPUC mandated resource adequacy requirements may result in physical delivery of excess energy that may not be in quantities that are expected to be used over a reasonable period in the normal course of business and may then be resold into the market. In addition, certain contracts do not meet the definition of clearly and closely related under SFAS No. 133 since pricing for certain renewable contracts is based on an unrelated commodity. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes for recorded derivatives are recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses – net; therefore, fair value changes do not affect earnings. Hedge accounting is not used for these transactions due to this regulatory accounting treatment.

In September 2007, the ISO allocated CRRs to SCE which will entitle SCE to receive (or pay) the value of transmission congestion at specific locations. These rights will act as an economic hedge against transmission congestion costs in the MRTU environment which was expected to be operational March 31, 2008 and has been delayed to the fall of 2008. The CRRs meet the definition of a derivative under SFAS No. 133. As of December 31, 2007 there were no quoted long-term market prices for the CRRs allocated to SCE. Although an auction was held in December 2007, the auction results did not provide sufficient evidence of long-term market prices. As a result of the insufficient market pricing evidence and the uncertainty of when the MRTU will become operational, SCE is unable to reasonably assess the fair value of the allocated CRRs as of December 31, 2007.

Any future fair value changes, given a MRTU market, will be recorded in purchased-power expense and offset through the provision for regulatory adjustments clauses as the CPUC allows these costs to be recovered from or refunded to customers through a regulatory balancing account mechanism. As a result, fair value changes are not expected to affect earnings.

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, 2007		**December 31, 2006**	
In millions	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Energy options	**$ —**	**$ 43**	$ —	$ 10
FTRs	**22**	**—**	—	—
Forward physicals (power) and tolling arrangements	**—**	**1**	—	1
Gas options, swaps and forward arrangements	**24**	**—**	—	101
Total	**$ 46**	**$ 44**	$ —	$ 112

Quoted market prices, if available, are used for determining the fair value of contracts, as discussed above. If quoted market prices are not available, internally maintained standardized or industry accepted models are used 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.

A 10% increase in energy prices at December 31, 2007 would increase the fair value of energy options by approximately $34 million; a 10% decrease in energy prices at December 31, 2007, would decrease the fair value by approximately $16 million. A 10% increase in energy prices at December 31, 2007 would increase the fair value of forward physicals (power) and tolling arrangements by approximately $20 million; a 10% decrease in energy prices at December 31, 2007, would decrease the fair value by approximately $20 million. A 10% increase in gas prices at December 31, 2007 would increase the fair value of gas options, swaps and forward arrangements by approximately $71 million; a 10% decrease in gas prices at December 31, 2007, would decrease the fair value by approximately $113 million. A 10% increase in energy prices at December 31, 2007 would increase the fair value of firm transmission rights by approximately $25 million; a 10% decrease in energy prices at December 31, 2007, would decrease the fair value by approximately $19 million.

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 interest rate-locks resulting in realized losses of $33 million. A related regulatory asset was recorded in this amount and SCE expects to amortize and recover this amount as interest expense associated with its 2008 financings.

SCE recorded net unrealized gains (losses) of $91 million, $(237) million and $90 million for the years ended December 31, 2007, 2006, and 2005, respectively. The 2007 unrealized gains were primarily due to changes in SCE's gas hedge portfolio mix as well as in increase in the natural gas futures market as of December 31, 2007 compared to December 31, 2006. Due to expected recovery through regulatory mechanisms unrealized gains and losses may temporarily affect cash flows, but are not expected to affect earnings.

Credit Risk

Credit risk arises primarily due to the chance that a counterparty under various purchase and sale contracts will not perform as agreed or pay SCE for energy products delivered. SCE uses a variety of strategies to mitigate its exposure to credit risk. SCE's risk management committee regularly reviews procurement credit exposure and approves credit limits for transacting with counterparties. Some counterparties are required to post collateral depending on the creditworthiness of the counterparty and the risk associated with the transaction. SCE follows the credit limits established in its CPUC-approved procurement plan, and accordingly believes that any losses which may occur should be fully recoverable from customers, and therefore are not expected to affect earnings.

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.

Results of Operations

Net Income Available for Common Stock

2007 vs. 2006

SCE's net income available for common stock was $707 million in 2007, compared with earnings of $776 million in 2006. The decrease was mainly due to a $130 million benefit related primarily to favorable resolution of tax and regulatory matters and $28 million of generator settlements, both recognized in 2006, and higher net interest expense in 2007. The decrease was partially offset by a $31 million benefit recognized in 2007, primarily related to the income tax treatment of certain costs including those associated with environmental remediation, higher operating margin, lower income taxes in 2007 and a tariff dispute settlement.

2006 vs. 2005

SCE's net income available for common stock was $776 million in 2006, compared with earnings of $725 million in 2005. The increase reflects the impact of higher net revenue authorized in the 2006 GRC decision, higher earnings from SCE's Mountainview plant and a 2006 benefit from a generator settlement, partially offset by higher income tax expense. Net income available for common stock in 2006 also include an $81 million benefit from resolution of an outstanding regulatory issue related to a portion of revenue collected during the 2001 – 2003 period for state income taxes and a $49 million benefit from favorable resolution of a state apportionment tax issue. Net income available for common stock in 2005 include a $61 million benefit from an IRS tax settlement and a $55 million benefit related to a favorable FERC decision on a SCE transmission proceeding.

Operating Revenue

The following table sets forth the major changes in operating revenue:

In millions	2007 vs. 2006	2006 vs. 2005
Operating revenue		
Rate changes and impact of tiered rate structure (including unbilled)	**$ (545)**	$ 1,441
Sales volume changes (including unbilled)	**119**	311
Balancing account over/under collections	**405**	(422)
Sales for resale	**120**	(463)
SCE's VIEs	**(6)**	(75)
Other (including inter company transactions)	**73**	20
Total	**$ 166**	$ 812

SCE's retail sales represented approximately 87%, 88% and 82% of operating revenue for the years ended December 31, 2007, 2006, and 2005, 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.

Total operating revenue increased by $166 million in 2007 compared to 2006 (as shown in the table above). The variances for the revenue components are as follows:

- Operating 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).

- Operating revenue resulting from sales volume changes was mainly due to customer growth as well as an increase in customer usage.

- SCE recognizes revenue, subject to balancing account treatment, equal to the amount of the actual costs incurred and up to its authorized revenue requirement. Any revenue collected in excess of actual power procurement-related costs incurred or above the authorized revenue requirement is not recognized as revenue and is deferred and recorded as regulatory liabilities to be refunded in future customer rates. Revenue collected below the authorized revenue requirement is recognized as revenue and recorded as a regulatory asset for future recovery. Power procurement-related costs incurred in excess of revenue billed are deferred in a balancing account and recorded as regulatory assets for recovery in future customer rates. In 2007, SCE deferred approximately $95 million compared to a deferral of approximately $515 million in 2006. The decrease in deferred revenue was mainly due to lower net overcollections (lower deferred costs partially offset by lower revenue collections of SCE's authorized revenue requirement) resulting from lower gas prices as compared to forecast and lower revenue in 2007 resulting from warmer weather in 2006.

- Operating 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.

- The increase in other revenue was primarily due to higher net investment earnings from SCE's nuclear decommissioning trusts. Due to regulatory treatment, the nuclear decommissioning trust investment earnings are offset in depreciation, decommissioning and amortization expense and as a result, have no impact on net income.

Total operating revenue increased by $812 million in 2006 compared to 2005 (as shown in the table above). The variances for the revenue components are as follows:

- Operating revenue from rate changes was mainly due to rate increases implemented throughout 2006, primarily relating to the implementation of SCE's 2006 ERRA forecast, implementation of the 2006 GRC decision and modification of the FERC transmission-related rates.
- Operating revenue resulting from sales volume changes was mainly due to an increase in kWhs sold resulting from record heat conditions experienced in the third quarter of 2006, SCE providing a greater amount of energy to its customers from its own sources in 2006, as compared to 2005, and customer growth.
- In 2006, SCE collected revenue in excess of actual costs incurred and as a result deferred approximately $515 million compared to a deferral of approximately $93 million in 2005, due to warmer weather and timing differences from sales and purchases of power subject to balancing account mechanisms.
- Operating 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 decreased due to a lesser amount of excess energy in 2006, as compared to 2005, due to higher demand in 2006 resulting from record heat conditions and lower availability of energy from SCE's own sources resulting from the Mohave shutdown and the San Onofre outages. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.
- SCE's VIE revenue represents the recognition of revenue resulting from the consolidation of four gas-fired power plants where SCE is considered the primary beneficiary. These VIEs affect SCE's revenue, but do not affect earnings; the decrease in revenue from SCE's VIEs is primarily due to lower natural gas prices in 2006, compared to 2005.
- The increase in other revenue was primarily due to higher net investment earnings from SCE's nuclear decommissioning trusts. Due to regulatory treatment, the nuclear decommissioning trust investment earnings are offset in depreciation, decommissioning and amortization expense and as a result, have no impact on net income.

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 none of these collections are recognized as revenue by SCE. These amounts were $2.3 billion, $2.5 billion, and $1.9 billion for the years ended December 31, 2007, 2006, and 2005, respectively.

Operating Expenses

Fuel Expense

SCE's fuel expense increased $79 million in 2007 and decreased $81 million in 2006. The 2007 increase was mainly due to an increase at SCE's Mountainview plant of $70 million, due to higher generation and higher gas costs in 2007 compared to 2006; higher nuclear fuel expense of $20 million in 2007 resulting primarily from a planned refueling and maintenance outage at SCE's San Onofre Unit 2 and 3 in 2006; partially offset by lower fuel expense of approximately $15 million, related to the SCE VIE projects. The 2006 decrease was due to lower fuel expense of approximately $90 million at SCE's Mohave Generating Station resulting from the plant shutdown on December 31, 2005 (see "Regulatory Matters — Mohave Generating Station and Related Proceedings" for further discussion); lower fuel expense of $200 million related to SCE's consolidated VIEs, driven by lower natural gas prices; and lower nuclear fuel expense of $15 million resulting primarily from planned refueling and maintenance outages at SCE's San Onofre Unit 2 and Unit 3, partially offset by higher fuel expense of $240 million resulting from SCE's Mountainview plant which became operational in December 2005.

Purchased-Power Expense

The following is a summary of purchased-power expense:

In millions **For the Year Ended December 31,**	**2007**	2006	2005
Purchased power	**$ 3,117**	$ 3,013	$ 3,113
Unrealized (gains) losses on economic hedging activities – net	**(91)**	237	(90)
Realized (gains) losses on economic hedging activities – net	**132**	339	(115)
Energy settlements and refunds	**(34)**	(180)	(286)
Total purchased-power expense	**$ 3,124**	$ 3,409	$ 2,622

Total purchased-power expense decreased $285 million in 2007 and increased $787 million in 2006.

Purchased power, in the table above, increased $104 million in 2007 compared to a decrease of $100 million in 2006. 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 $60 million, resulting from an increase in the average spot natural gas prices (as discussed further below); and higher firm transmission right costs of $40 million. The 2007 increase was partially offset by a decrease in ISO-related energy costs of $150 million and $60 million in purchased power expense associated with power contracts that were modified under EITF No. 01-8 in 2006 (see "— Commitments and Indemnities" for further discussion). The 2006 decrease in purchased power resulted from lower power purchased and lower prices from QFs of approximately $95 million (as further discussed below).

Net realized and unrealized losses on economic hedging activities, in the table above, was $41 million in 2007 compared to $576 million in 2006 (see "Market Risk Exposures — Commodity Price Risk" for further discussion). The changes in net realized and unrealized (gains) losses on economic hedging activities primarily resulted from changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market as of December 31, 2007, compared to December 31, 2006. Due to expected recovery through regulatory mechanisms realized and unrealized gains and losses may temporarily affect cash flows, but are not expected to affect earnings (see "Market Risk Exposures — Commodity Price Risk" for further discussion).

SCE energy settlement refunds and generator settlements decreased in 2007 by $146 million compared to $106 million in 2006 (See "Regulatory Matters — Current Regulatory Developments — FERC Refund Proceedings" for further discussion).

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.

Provisions for Regulatory Adjustment Clauses – Net

Provisions for regulatory adjustment clauses – net increased $246 million in 2007 and decreased $410 million in 2006. The 2007 variance reflects net unrealized gains on economic hedging activities of approximately $91 million in 2007, compared to net unrealized losses on economic hedging activities of approximately $237 million in 2006 (mentioned above in purchased-power expense). The 2007 variance also reflects approximately $70 million in energy refunds and generator settlements recorded in 2006; the resolution of a $135 million one-time gain related to a portion of revenue collected during the 2001 – 2003 period related to state income taxes recorded in the second quarter of 2006; $60 million associated with power contracts that were modified under EITF No. 01-8 in 2006 (see "— Commitments and Indemnities" for further discussion); and approximately $255 million in operation and maintenance-related expenses resulting from timing differences that are being recognized in revenue which are being recovered through regulatory mechanisms.

The 2006 decrease was mainly due to net unrealized losses related to economic hedging transactions of approximately $237 million in 2006, that, if realized, would be recovered from ratepayers, compared to unrealized gains of $90 million in 2005, which, if realized, would be refunded to ratepayers (see "Market Risk Exposures — Commodity Price Risk" for further discussion). The decrease also reflects lower energy refunds and generator settlements of $105 million (discussed above) and the resolution of a one-time issue related to a portion of revenue collected during the 2001 – 2003 period related to state income taxes. SCE was able to determine through the 2006 GRC decision and other regulatory proceedings that the level of revenue collected during that period was appropriate, and as a result recorded a pre-tax gain of $135 million in 2006. The decrease was partially offset by higher net overcollections of purchased power, fuel, and operation and maintenance expenses of approximately $240 million.

Other Operation and Maintenance Expense

SCE's other operation and maintenance expense increased $162 million in 2007 and $155 million in 2006. Certain of SCE's operation and maintenance expense accounts are recovered through regulatory mechanisms approved by the CPUC. The costs associated with these regulatory balancing accounts increased $98 million in 2007 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. In addition to the increase in balancing account related operation and maintenance costs the 2007 increase was due to higher transmission and distribution maintenance cost of approximately $20 million; higher health care costs and other benefits of $30 million; 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 2006. The 2006 increase was mainly due to higher generation-related costs of approximately $80 million resulting from the planned refueling and maintenance outages at SCE's San Onofre Unit 2 and Unit 3 and higher maintenance costs at Palo Verde, partially offset by lower costs at Mohave resulting from the plant ceasing operations on December 31, 2005; higher transmission and distribution maintenance costs of approximately $60 million; and increased operation and maintenance expense of $20 million at SCE's Mountainview plant as a result of the plant becoming operational at the end of 2005. Upon implementation of the 2006 GRC in May 2006, costs related to the Mohave shutdown, pensions, PBOPs, and the employee results sharing incentive plan are recovered through balancing account mechanisms.

Depreciation, Decommissioning and Amortization Expense

SCE's depreciation, decommissioning and amortization expense increased $68 million in 2007 and increased $111 million in 2006. The 2007 increase was primarily due to transmission and distribution asset additions resulting in increased depreciation expense of $50 million (see "Liquidity — Capital Expenditures" for a further discussion). The 2007 increase also reflects a $25 million increase in nuclear decommissioning trust earnings net of other-than-temporary impairment losses associated with the nuclear decommissioning trust funds. Due to its regulatory treatment, investment impairment losses and trust earnings are recorded in operating revenue and are offset in decommissioning expense and have no impact on net income. The increase in 2006 was mainly due to an increase in depreciation expense resulting from additions to transmission and distribution assets, as well as an increase from the implementation of the depreciation rates authorized in the 2006 GRC decision, and higher net investment earnings from SCE's nuclear decommissioning trusts.

Other Income and Deductions

Interest income

SCE's interest income decreased $14 million in 2007 and increased $14 million in 2006. The 2007 decrease was mainly due to lower interest income resulting from lower undercollections on balancing accounts in 2007, as compared to 2006. The 2006 increase was mainly due to interest income from balancing accounts that were undercollected during both 2006 and 2005, and higher short-term interest rates in 2006, as compared to 2005.

Other Nonoperating Income

SCE's other nonoperating income decreased $42 million in 2006. The 2006 decrease was mainly due to the recognition of approximately $45 million in incentives related to demand-side management and energy efficiency performance recorded in 2005. In addition, SCE recorded shareholder incentives of $6 million and $23 million in 2006 and 2005, respectively (see "Regulatory Matters — Current Regulatory Developments — FERC Refund Proceedings" for further discussion).

Interest Expense — Net of Amounts Capitalized

SCE's interest expense – net of amounts capitalized increased $29 million in 2007 and increased $40 million in 2006. The 2007 increase was mainly due to higher interest expense on balancing account overcollections in 2007, as compared to 2006. The increase was also due to higher interest expense on long-term debt resulting from higher balances outstanding during 2007, as compared to 2006. The 2006 increase was mainly due to a 2005 reversal of approximately $25 million of accrued interest expense as a result of a FERC decision allowing recovery of transmission-related costs. The 2006 increase also reflects higher interest expense on balancing account overcollections in 2006, compared to 2005.

Other Nonoperating Deductions

SCE's other nonoperating deductions decreased $15 million in 2007 and decreased $5 million in 2006. The 2007 decrease was mainly due to a penalty accrual of $23 million under the customer satisfaction performance mechanism recognized in 2006.

Income Tax Expense (Benefit) — Continuing Operations

The composite federal and state statutory income tax rate was approximately 40% for all periods presented. The lower effective tax rate of 30.8% realized in 2007 was primarily due to reductions made to the income tax reserve to reflect progress in an administrative appeals process with the IRS related to SCE's income tax treatment of costs associated with environmental remediation and due to reductions made to the income tax reserve to reflect settlement of a state tax issue related to the April 2007 State Notice of Proposed Adjustment discussed below. The lower effective tax rate of 34.6% realized in 2006 was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue (see "Other Developments — Federal and State Income Taxes") partially offset by tax reserve accruals. The lower effective tax rate of 28.1% realized in 2005 was primarily due to settlement of the 1991-1993 IRS audit cycle as well as adjustments made to the tax reserve to reflect the issuance of new IRS regulations and the favorable settlement of other federal and state tax audit issues.

As a matter of course, Edison International is regularly audited by federal, state and foreign taxing authorities. For further discussion of this matter, see "Other Developments — Federal and State Income Taxes."

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 $3.0 billion in 2007, $2.6 billion in 2006, and $2.4 billion in 2005. 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 (see "Regulatory Matters — Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates" for further discussion).

The 2006 increase was mainly due to an increase in cash collected from SCE's customers due to increased rates and increased sales volume due to warmer weather in 2006, as compared to 2005, which contributed to higher balancing account overcollections in 2006, as compared to 2005. The 2006 increase was also attributable to a decrease of $123 million in required margin and collateral deposits in 2006, compared to an increase of $112 million in 2005. The change resulted from a decrease in forward market prices in 2006 from 2005 and settlement of hedge contracts during 2006. In addition, the 2006 change was also due to the timing of cash receipts and disbursements related to working capital items and higher income taxes paid in 2006, compared to 2005. The 2005 change in cash provided by operating activities from continuing operations was mainly due to an increase in income from continuing operations, and the results from the timing of cash receipts and disbursements related to working capital items.

Cash Flows from Financing Activities

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

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; and
- Financing activities in 2007 include dividend payments of $135 million paid to Edison International.

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

- 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; and

- Financing activities in 2006 also included dividend payments of $251 million paid to Edison International.

Financing activities in 2005 included activities related to the rebalancing of SCE's capital structure:

- In January 2005, SCE issued $650 million of first and refunding mortgage bonds which consisted of $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds from this issuance were used to redeem the remaining $50,000 of its 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and $650 million of the $966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B);
- In March 2005, SCE issued $203 million of 3.55% pollution control bonds due in 2029. The proceeds from this issuance were used to redeem $49 million of 7.20% pollution control bonds due in 2021 and $155 million of 5.875% pollution control bonds due in 2023. This transaction was treated as a noncash financing activity;
- In April 2005, SCE issued 4,000,000 shares of Series A preference stock (noncumulative, 100% liquidation value) and received net proceeds of approximately $394 million. Approximately $81 million of the proceeds was used to redeem all the outstanding shares of its 7.23% Series $100 cumulative preferred stock, and approximately $64 million of the proceeds was used to redeem all the outstanding shares of its 6.05% Series $100 cumulative preferred stock;
- In June 2005, SCE issued $350 million of 5.35% first and refunding mortgage bonds due in 2035 (Series 2005E). A portion of the proceeds from this issuance were used to redeem $316 million of its 8% first and refunding mortgage bonds due in 2007 (Series 2003B);
- In August 2005, SCE issued $249 million of variable rate pollution control bonds due in 2035. The proceeds from this issuance were used to redeem $29 million of 6.90% pollution control bonds due in 2017, $30 million of 6.0% pollution control bonds due in 2027 and $190 million of 6.40% pollution control bonds due in 2024. This transaction was treated as a noncash financing activity;
- In September 2005, SCE issued 2,000,000 shares of Series B preference stock (noncumulative, $100 liquidation value) and received net proceeds of approximately $197 million; and
- Financing activities in 2005 also include dividend payments of $234 million paid to Edison International.

Cash Flows from Investing Activities

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

Net cash used by investing activities in 2007 was $2.4 billion in 2007, $2.3 billion in 2006, and $1.8 billion in 2005.

Investing activities include capital expenditures of $2.3 billion, $2.2 billion and $1.8 billion in 2007, 2006, and 2005, respectively, primarily for transmission and distribution assets. Capital expenditures include $3 million, $13 million and $166 million in 2007, 2006 and 2005, respectively, related to Mountainview and approximately $123 million, $81 million and $59 million in 2007, 2006 and 2005, respectively, for nuclear fuel acquisitions.

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. Many of the critical accounting estimates and policies discussed below generally do not impact SCE's earnings since SCE applies accounting principles for rate-regulated enterprises. However, these critical accounting estimates and policies may impact amounts reported on the consolidated balance sheets.

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 capital. 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, 2007, the consolidated balance sheets included regulatory assets of $2.9 billion and regulatory liabilities of $4.5 billion. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund 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.

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 setoff, 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 meet the definition of a derivative instrument, did not qualify for the normal sales and purchase exception, and hedge accounting was not elected, 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.

Income Taxes

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

The SFAS No. 109, Accounting for Income Taxes, requires the asset and liability approach for financial accounting and reporting for deferred income taxes. SCE uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. FIN 48 clarifies the accounting for uncertain tax positions. FIN 48 (adopted on January 1, 2007) 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. Management continues to monitor and assess new income tax developments.

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. As further described in "Other Developments — Federal and State Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain issues at SCE.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. Management uses judgment in determination of 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 caption "accrued taxes" 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. See "New Accounting Pronouncements."

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 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, respectively. 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

SCE'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 are 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, 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 effective January 2007, receive contributions of approximately $46 million per year. As of December 31, 2007, the decommissioning trust balance was $3.4 billion. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. 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 market value.

SCE's nuclear decommissioning trusts are accounted for in accordance with SFAS No. 115, Accounting for Certain Investments in Debt Equity Securities, 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. Contributions, earnings, and realized gains and losses (including other than temporary impairments) are recognized as revenue, and due to regulatory accounting treatment, also represent an increase in the nuclear obligation and increase decommissioning expense. 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 revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the last day of the current month and the last day of the prior month. If the fair value on both days is less than the cost of 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 $89 million as of December 31, 2007 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, 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. Three yield curves were considered: two corporate yield curves (Citigroup and AON) and a curve based on treasury rates (plus 90 basis points). SCE also compares the yield curve analysis against the Moody's AA Corporate bond rate. At the December 31, 2007 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 on the pension plan assets were 8.8%, 14.7% and 9.6% for the one-year, five-year and ten-year periods ended December 31, 2007, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 6.9%, 12.6%, and 6.8% 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, 2007, this cumulative difference amounted to a regulatory liability of $75 million, meaning that the rate-making method has recognized $75 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 the 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, 2007, SCE's PBOP plans had a $2.2 billion benefit obligation. Total expense for these plans was $49 million for 2007. The health care cost trend rate is 9.25% for 2007, 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, 2007 by $259 million and annual aggregate service and interest costs by $18 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2007 by $231 million and annual aggregate service and interest costs by $16 million.

NEW ACCOUNTING PRONOUNCEMENTS

Accounting Pronouncements Adopted

In July 2006, the FASB issued FIN 48 which clarifies the accounting for uncertain tax positions. 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. SCE adopted FIN 48 effective January 1, 2007. Implementation of FIN 48 resulted in a cumulative-effect adjustment that increased retained earnings by $213 million upon adoption. SCE will continue to monitor and assess new income tax developments.

Accounting Pronouncements Not Yet Adopted

In April 2007, the FASB issued FIN 39-1. FIN 39-1 amends paragraph 3 of FIN No. 39 to replace the terms conditional contracts and exchange contracts with the term derivative instruments as defined in SFAS No. 133. FIN 39-1 also states that under master netting arrangements if collateral is based on fair value, then it must be netted with the fair value of derivative assets/liabilities if an entity qualified and elected the option to net those amounts. SCE will adopt FIN 39-1 in the first quarter of 2008. The adoption is expected to result in netting a portion of margin and cash collateral deposits with derivative liabilities on SCE's consolidated balance sheets, but will have no impact on SCE's consolidated statements of income.

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 will adopt this pronouncement in the first quarter of 2008 and may elect to report certain financial assets and liabilities at fair value. The adoption is not expected to result in a cumulative-effect adjustment to retained earnings.

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 will adopt SFAS No. 157 in the first quarter of 2008. The adoption is not expected to result in any retrospective adjustments to its financial statements. The accounting requirements for employers' pension and other postretirement benefit plans is effective at the end of 2008 which is the next measurement date for these benefit plans. The effective date will be January 1, 2009 for asset retirement obligations and other nonfinancial liabilities which are not measured or disclosed on a recurring basis (at least annually).

In December 2007, the FASB issued SFAS No. 160, which requires an entity to clearly identify and present ownership interests in subsidiaries held by parties other than the entity in the consolidated financial statements within the equity section but separate from the entity's equity. 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 on January 1, 2009. SCE is currently evaluating the impact of adopting SFAS No. 160 on its consolidated financial statements. In accordance with this standard, SCE will reclassify minority interest to a component of shareholder's equity (at December 31, 2007 this amount was $446 million).

COMMITMENTS AND INDEMNITIES

SCE's commitments as of December 31, 2007, for the years 2008 through 2012 and thereafter are estimated below:

In millions	2008	2009	2010	2011	2012	Thereafter
Long-term debt maturities and interest	$ 269	$ 413	$ 495	$ 244	$ 244	$ 8,886
Fuel supply contract payments	101	79	71	68	64	241
Purchased-power capacity payments	410	324	294	290	339	1,152
Operating lease obligations	617	697	655	436	270	1,515
Capital lease obligations	4	3	4	1	1	7
Other commitments	5	5	6	6	6	25
Employee benefit plans contributions[1]	84	—	—	—	—	—
Total[2]	$ 1,490	$ 1,521	$ 1,525	$ 1,045	$ 924	$ 11,826

(1) Amount includes estimated contributions to the pension and PBOP plans. The estimated contributions for SCE are not available beyond 2008.

(2) At December 31, 2007, SCE had a total net liability recorded for uncertain tax positions of $257 million, which is excluded from the table. Edison International cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the IRS.

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 purchased-power 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. 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. The fair value changes for these power purchase contracts were previously recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses — net; therefore, 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, 2007, the net liability was $59 million. At December 31, 2007, SCE had 67 power contracts classified as operating leases. Operating lease expense for power purchases was $297 million in 2007, $188 million in 2006, and $68 million in 2005. In addition, SCE executed a power purchase contract in late 2005 and an additional power purchase contract in June 2007 which met the requirements for capital leases. These capital leases have a net commitment of $20 million at December 31, 2007 and $13 million at December 31, 2006. SCE's capital lease executory costs and interest expense was $2 million in 2007 and $3 million in 2006.

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 $53 million through 2016 (approximately $6 million per year).

Indemnities

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the 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, 2007.

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 2007, 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 and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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 8 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of December 31, 2005, stock-based compensation as of January 1, 2006, defined benefit pension and other post retirement plans as of December 31, 2006, and uncertain tax positions as of January 1, 2007.

PricewaterhouseCoopers LLP

Los Angeles, California
February 27, 2008

Consolidated Statements of Income			**Southern California Edison Company**
In millions **Year ended December 31,**	**2007**	**2006**	**2005**
Operating revenue	**$ 10,478**	$ 10,312	$ 9,500
Fuel	**1,191**	1,112	1,193
Purchased power	**3,124**	3,409	2,622
Provisions for regulatory adjustment clauses – net	**271**	25	435
Other operation and maintenance	**2,840**	2,678	2,523
Depreciation, decommissioning and amortization	**1,094**	1,026	915
Property and other taxes	**217**	206	193
Net gain on sale of utility property and plant	**—**	(1)	(10)
Total operating expenses	**8,737**	8,455	7,871
Operating income	**1,741**	1,857	1,629
Interest income	**44**	58	44
Other nonoperating income	**89**	85	127
Interest expense – net of amounts capitalized	**(429)**	(400)	(360)
Other nonoperating deductions	**(45)**	(60)	(65)
Income before tax and minority interest	**1,400**	1,540	1,375
Income tax expense	**337**	438	292
Minority interest	**305**	275	334
Net income	**758**	827	749
Dividends on preferred and preference stock not subject to mandatory redemption	**51**	51	24
Net income available for common stock	**$ 707**	$ 776	$ 725

Consolidated Statements of Comprehensive Income

In millions **Year ended December 31,**	**2007**	**2006**	**2005**
Net income	**$ 758**	$ 827	$ 749
Other comprehensive income (loss), net of tax:			
Termination and amortization of cash flow hedges – net of income tax expense of \$3 and \$2 for 2006 and 2005	**—**	5	2
Pension and postretirement benefits other than pensions:			
Net loss arising during period – net of income tax benefit of \$2 for 2007	**(3)**	—	—
Amortization of net loss included in expense – net of income tax expense of \$1 for 2007	**2**	—	—
Minimum pension liability adjustment – net of income tax expense (benefit) of \$5 and \$(1) for 2006 and 2005	**—**	7	(1)
Comprehensive income	**$ 757**	$ 839	$ 750

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

Consolidated Balance Sheets		Southern California Edison Company
In millions December 31,	2007	2006
ASSETS		
Cash and equivalents	**$ 252**	$ 83
Restricted cash	**—**	56
Margin and collateral deposits	**37**	55
Receivables, less allowances of $34 and $29 for uncollectible accounts at respective dates	**725**	939
Accrued unbilled revenue	**370**	303
Inventory	**283**	232
Accumulated deferred income taxes – net	**146**	250
Derivative assets	**54**	56
Regulatory assets	**197**	554
Other current assets	**188**	54
Total current assets	**2,252**	2,582
Nonutility property – less accumulated provision for depreciation of $701 and $633 at respective dates	**1,000**	1,046
Nuclear decommissioning trusts	**3,378**	3,184
Other investments	**69**	62
Total investments and other assets	**4,447**	4,292
Utility plant, at original cost:		
Transmission and distribution	**18,940**	17,606
Generation	**1,767**	1,465
Accumulated provision for depreciation	**(5,174)**	(4,821)
Construction work in progress	**1,693**	1,486
Nuclear fuel, at amortized cost	**177**	177
Total utility plant	**17,403**	15,913
Regulatory assets	**2,721**	2,818
Derivative assets	**28**	17
Other long-term assets	**629**	488
Total long-term assets	**3,378**	3,323
Total assets	**$ 27,480**	$ 26,110

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,**	**2007**	**2006**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**$ 500**	$ —
Long-term debt due within one year	**—**	396
Accounts payable	**914**	856
Accrued taxes	**42**	193
Accrued interest	**126**	114
Counterparty collateral	**42**	36
Customer deposits	**218**	198
Book overdrafts	**204**	140
Derivative liabilities	**100**	99
Regulatory liabilities	**1,019**	1,000
Other current liabilities	**548**	624
Total current liabilities	**3,713**	3,656
Long-term debt	**5,081**	5,171
Accumulated deferred income taxes – net	**2,556**	2,675
Accumulated deferred investment tax credits	**105**	112
Customer advances	**155**	160
Derivative liabilities	**13**	77
Power-purchase contracts	**22**	32
Accumulated provision for pensions and benefits	**786**	809
Asset retirement obligations	**2,877**	2,749
Regulatory liabilities	**3,433**	3,140
Other deferred credits and other long-term liabilities	**1,136**	802
Total deferred credits and other liabilities	**11,083**	10,556
Total liabilities	**19,877**	19,383
Commitments and contingencies (Note 6)		
Minority interest	**446**	351
Common stock, no par value (434,888,104 shares outstanding at each date)	**2,168**	2,168
Additional paid-in capital	**507**	383
Accumulated other comprehensive loss	**(15)**	(14)
Retained earnings	**3,568**	2,910
Total common shareholder's equity	**6,228**	5,447
Preferred and preference stock not subject to mandatory redemption	**929**	929
Total shareholders' equity	**7,157**	6,376
Total liabilities and shareholders' equity	**$ 27,480**	$ 26,110

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,	2007	2006	2005
Cash flows from operating activities:			
Net income	**$ 758**	$ 827	$ 749
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**1,094**	1,026	915
Loss on impairment of nuclear decommissioning trusts	**58**	54	—
Other amortization	**95**	79	96
Stock-based compensation	**18**	27	21
Minority interest	**305**	275	334
Deferred income taxes and investment tax credits	**(111)**	(358)	34
Regulatory assets – long-term	**148**	92	387
Regulatory liabilities – long-term	**157**	18	(168)
Derivative assets – long-term	**(11)**	25	(42)
Derivative liabilities – long-term	**(64)**	(24)	97
Other assets	**(156)**	(119)	88
Other liabilities	**195**	325	(46)
Margin and collateral deposits – net of collateral received	**24**	(24)	70
Receivables and accrued unbilled revenue	**147**	51	(202)
Derivative assets – short-term	**2**	181	(211)
Derivative liabilities – short-term	**(32)**	12	74
Inventory and other current assets	**(185)**	(7)	(42)
Regulatory assets – short-term	**357**	(18)	17
Regulatory liabilities – short-term	**19**	318	192
Book overdrafts	**64**	—	—
Accrued interest and taxes	**74**	(41)	(126)
Accounts payable and other current liabilities	**17**	(138)	184
Net cash provided by operating activities	**2,973**	2,581	2,421
Cash flows from financing activities:			
Long-term debt issued	**—**	900	1,000
Long-term debt issuance costs	**(1)**	(24)	(20)
Long-term debt repaid	**(207)**	(352)	(1,040)
Bonds repurchased	**(37)**	—	—
Issuance of preference stock	**—**	196	591
Redemption of preferred stock	**—**	—	(148)
Rate reduction notes repaid	**(246)**	(246)	(246)
Short-term debt financing – net	**500**	—	(88)
Book overdrafts	**—**	(118)	25
Shares purchased for stock-based compensation	**(135)**	(107)	(122)
Proceeds from stock option exercises	**56**	45	53
Excess tax benefits related to stock option exercises	**28**	17	—
Minority interest	**(210)**	(322)	(345)
Dividends paid	**(186)**	(300)	(234)
Net cash used by financing activities	**(438)**	(311)	(574)
Cash flows from investing activities:			
Capital expenditures	**(2,286)**	(2,226)	(1,808)
Proceeds from nuclear decommissioning trust sales	**3,697**	3,010	2,067
Purchases of nuclear decommissioning trust investments and other	**(3,830)**	(3,150)	(2,159)
Sales of short-term investments	**7,069**	6,446	2,748
Purchases of short-term investments	**(7,069)**	(6,418)	(2,776)
Restricted cash	**56**	1	4
Customer advances for construction and other investments	**(3)**	7	98
Net cash used by investing activities	**(2,366)**	(2,330)	(1,826)
Net increase (decrease) in cash and equivalents	**169**	(60)	21
Cash and equivalents, beginning of year	**83**	143	122
Cash and equivalents, end of year	**$ 252**	$ 83	$ 143

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

Consolidated Statements of Changes in Common Shareholders' 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, 2004	$ 2,168	$ 350	$ (17)	$ 2,020	$ 4,521
Net income				749	749
Other comprehensive income			1		1
Dividends declared on common stock				(285)	(285)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(24)	(24)
Shares purchased for stock-based compensation		(19)		(95)	(114)
Proceeds from stock option exercises				53	53
Noncash stock-based compensation and other		11			11
Excess tax benefits related to stock option exercises		29			29
Capital stock expense and other		(10)		(1)	(11)
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 option exercises		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 option exercises		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

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 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' management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as appropriate.

Certain prior-year amounts were reclassified to conform to the December 31, 2007 financial statement presentation.

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 and equivalents consist of cash and cash equivalents. Cash equivalents consist of other investments of $83 million and $1 million at December 31, 2007 and 2006, respectively, with original maturities of three months or less. Additionally, cash and equivalents of $110 million and $78 million at December 31, 2007 and 2006, respectively, are included for the VIE segment. For a discussion of restricted cash, see "Restricted Cash."

Deferred Financing Costs

Debt premium, discount and issuance expenses are deferred and amortized on a straight-line basis 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 $331 million at December 31, 2007 and $318 million at December 31, 2006 reflected in “regulatory assets” in the long-term section of the consolidated balance sheets. SCE had unamortized debt issuance costs of $40 million at December 31, 2007 and $46 million at December 31, 2006 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 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 does not expect the counterparties to fail to meet their obligations.

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 or a foreign currency exposure, the effective portion of the gain or loss is initially recorded as a separate component of shareholders’ equity under the caption “Accumulated other comprehensive income (loss),” and subsequently reclassified into earnings when the forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when SCE has the legal right of setoff, 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.

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 for recorded derivatives are recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses, as the CPUC allows these costs to be recovered from or refunded to customers through a regulatory balancing account mechanism. 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-locks to mitigate interest rate risk associated with future financings. SCE expects to recover any fair value changes associated with the interest-lock derivative instruments 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.

Dividend Restrictions

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2007, SCE's 13-month weighted-average common equity component of total capitalization was 50.59% resulting in the capacity to pay $308 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 a separate return.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each of the jurisdictions in which it operates. SCE uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. FIN 48 clarifies the accounting for uncertain tax positions. FIN 48 (adopted on January 1, 2007) 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. Management continues to monitor and assess new income tax developments.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are deferred and amortized over the lives of the related properties. 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 first-in, first-out method for fuel and the average cost method for 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 counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits varies based on changes in the value of the agreements. Deposits with counterparties and brokers earn interest at various rates.

New Accounting Pronouncements

Accounting Pronouncements Adopted

In July 2006, the FASB issued FIN 48 which clarifies the accounting for uncertain tax positions. 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. SCE adopted FIN 48 effective January 1, 2007. Implementation of FIN 48 resulted in a cumulative-effect adjustment that increased retained earnings by $213 million upon adoption. SCE will continue to monitor and assess new income tax developments.

Accounting Pronouncements Not Yet Adopted

In April 2007, the FASB issued FIN 39-1. FIN 39-1 amends paragraph 3 of FIN No. 39 to replace the terms conditional contracts and exchange contracts with the term derivative instruments as defined in SFAS No. 133. FIN 39-1 also states that under master netting arrangements if collateral is based on fair value, then it must be netted with the fair value of derivative assets/liabilities if an entity qualified and elected the option to net those amounts. SCE will adopt FIN 39-1 in the first quarter of 2008. The adoption is expected to result in netting a portion of margin and cash collateral deposits with derivative liabilities on SCE’s consolidated balance sheets, but will have no impact on SCE’s consolidated statements of income.

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 will adopt this pronouncement in the first quarter of 2008 and may elect to report certain financial assets and liabilities at fair value. The adoption is not expected to result in a cumulative-effect adjustment to retained earnings.

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 will adopt SFAS No. 157 in the first quarter of 2008. The adoption is not expected to result in any retrospective adjustments to its financial statements. The accounting requirements for employers’ pension and other postretirement benefit plans is effective at the end of 2008 which is the next measurement date for these benefit plans. The effective date will be January 1, 2009 for asset retirement obligations and other nonfinancial liabilities which are not measured or disclosed on a recurring basis (at least annually).

In December 2007, the FASB issued SFAS No. 160, which requires an entity to clearly identify and present ownership interests in subsidiaries held by parties other than the entity in the consolidated financial statements within the equity section but separate from the entity’s equity. 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 on January 1, 2009. SCE is currently evaluating the impact of adopting SFAS No. 160 on its consolidated financial statements. In accordance with this standard, SCE will reclassify minority interest to a component of shareholder's equity (at December 31, 2007 this amount was $446 million).

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. Contributions, earnings, and realized gains and losses (including other than temporary impairments) are recognized as revenue, and due to regulatory accounting treatment, also represent an increase in the nuclear obligation and increase decommissioning expense. 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 revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the first and last day of each month. If the fair value on both days is less than the weighted-average 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.

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 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.

Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.2% for 2007, 4.2% for 2006 and 3.9% for 2005.

AFUDC – equity was $46 million in 2007, $32 million in 2006 and $25 million in 2005. AFUDC – debt was $24 million in 2007, $18 million in 2006 and $14 million in 2005.

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	25 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 both 2007 and 2006, and $16 million in 2005. 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 2007, 3.8% for 2006 and 3.6% for 2005. 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 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 purchased power 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

Four EME subsidiaries have 49% to 50% ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. Beginning March 31, 2004, SCE consolidates these projects. See Note 14 for further information regarding VIEs. These variable interest projects hold $26 million in long-term debt due to EME with an interest rate of 5%, due in April 2008. This is included in long-term debt on the consolidated balance sheet.

Restricted Cash

SCE's restricted cash represents amounts used exclusively to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity. The rate reduction notes were repaid in December 2007. SCE had no restricted cash as of December 31, 2007.

Revenue Recognition

Operating revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each year. Amounts charged for services rendered are based on CPUC-authorized rates and FERC-approved rates, which provide an authorized rate of return, and recovery of operation and maintenance and capital-related carrying costs. 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. In accordance with SFAS No. 71, SCE recognizes revenue, subject to balancing account treatment, equal to the amount of actual costs incurred and up to its authorized revenue requirement. Any revenue collected in excess of actual costs incurred or above the authorized revenue requirement is not recognized as revenue and is deferred and recorded as regulatory liabilities. Costs incurred in excess of revenue billed are deferred in a balancing account and recorded as regulatory assets for recovery in future rates.

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 ($2.3 billion in 2007, $2.5 billion in 2006 and $1.9 billion in 2005) 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 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 $104 million, $107 million and $82 million for the years ended December 31, 2007, 2006 and 2005, 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 revenue.

Short-term Investments

At different times during 2007, 2006 and 2005, 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, 2007 and 2006. Both sales and purchases of the notes were $7 billion, $6 billion and $3 billion for the years ended December 31, 2007, 2006 and 2005, respectively. There were no realized or unrealized gains or losses. The consolidated statements of cash flows were revised to reflect the 2006 and 2005 sales and purchases activity on a gross basis.

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, 2007, Edison International had approximately 8.4 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 $28 million and $17 million of excess tax benefits are classified as financing cash inflow in 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, and would have increased $3 million for 2005.

Total stock-based compensation expense, net of amounts capitalized, (reflected in the caption “other operation and maintenance” on the consolidated statements of income) was $21 million, $27 million and $43 million for 2007, 2006 and 2005, respectively. The income tax benefit recognized in the income statement was $8 million, $11 million and $17 million for 2007, 2006 and 2005, respectively. Total stock-based compensation cost capitalized was $4 million and $6 million for 2007 and 2006, respectively.

The following table illustrates the effect on net income available for common stock if SCE had used the fair-value accounting method for 2005.

In millions	**Year ended December 31, 2005**
Net income available for common stock, as reported	$ 725
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	26
Less: stock-based compensation expense using the fair-value accounting method – net of tax	24
Pro forma net income available for common stock	$ 727

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 and unrealized gains and losses arising from derivative instruments are reflected in purchased-power expense and offset through the provision for regulatory adjustment clauses – net on the consolidated statements of income and thus 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,**	**2007**	**2006**	**2005**
Purchased power	**$ 3,117**	$ 3,013	$ 3,113
Unrealized (gains) losses on economic hedging activities – net	**(91)**	237	(90)
Realized losses on economic hedging activities – net	**132**	339	(115)
Energy settlements and refunds	**(34)**	(180)	(286)
Total purchased-power expense	**$ 3,124**	$ 3,409	$ 2,622

The changes in net unrealized and realized (gains) losses on economic hedging activities primarily resulted from changes in SCE’s gas hedge portfolio mix as well as in increase in the natural gas futures market. Due to expected recovery through regulatory mechanisms unrealized gains and losses may temporarily affect cash flows, but do not affect earnings.

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, 2007, SCE was in compliance with this debt covenant. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance a 10% rate reduction mandated by state law beginning in 1998. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property was a current property right created by the restructuring legislation and a financing order of the CPUC and consisted generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes were repaid over 10 years with the final principal payment made in December 2007, through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The nonbypassable rates being charged to customers are expected to cease at the time of SCE's next consolidated rate change which is expected to be in March 2008. All amounts collected subsequent to the final principal payment made in December 2007 will be refunded to ratepayers. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States of America, SCE Funding LLC is consolidated with SCE and the rate reduction notes were shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. As a result of the payment of the bonds, SCE Funding LLC terminated its registration on December 27, 2007 and is no longer required to file reports with the U.S. Securities and Exchange Commission.

Long-term debt is:

In millions December 31,	2007	2006
First and refunding mortgage bonds:		
2009 – 2037 (4.65% to 6.00% and variable)	**$ 3,375**	$ 3,525
Rate reduction notes:		
2007 (6.42%)	**—**	246
Pollution-control bonds:		
2015 – 2035 (2.9% to 5.55% and variable)	**1,196**	1,196
Bonds repurchased	**(37)**	—
Debentures and notes:		
2010 – 2053 (5.06% to 7.625%)	**557**	611
Long-term debt due within one year	**—**	(396)
Unamortized debt discount – net	**(10)**	(11)
Total	**$ 5,081**	$ 5,171

Note: Rates and terms as of December 31, 2007

Long-term debt maturities and sinking-fund requirements for the next five years are: 2008 – zero, 2009 – $150 million; 2010 – $250 million; 2011 and 2012 – zero.

In January 2008, SCE issued $600 million of 5.95% first and 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.

The interest rates on one issue of SCE's pollution control bonds insured by FGIC, totaling $249 million, are reset every 35 days through an auction process. Due to a loss of confidence in the creditworthiness of the bond insurers, there has been a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds have risen. Consequently, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and $187 million in January and February 2008. The bonds remain outstanding and have not been retired or cancelled. The instruments under which the bonds were issued allow SCE to convert the bonds to other short-term variable-rate, term rate or fixed-rate modes. SCE may remarket the bonds in a term rate mode in the first half of 2008 and terminate the insurance covering the bonds.

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, 2007, the outstanding short-term debt was $500 million at a weighted-average interest rate of 5.29%. There was no outstanding short-term debt at December 31, 2006.

Lines of Credit

On February 23, 2007, SCE amended its credit facility, increasing the amount of borrowing capacity to $2.5 billion, extending the maturity to February 2012 and removing the first mortgage bond collateral pledge. As a result of removing the first mortgage bond security, the credit facility's pricing changed to an unsecured basis per the terms of the credit facility agreement. At December 31, 2007, the $2.5 billion credit facility supported $229 million in letters of credit and $500 million of short-term debt leaving $1.77 billion in available credit under its credit line.

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,	2007	2006	2005
Current:				
Federal		**$ 295**	$ 681	$ 255
State		**94**	159	84
		389	840	339
Deferred:				
Federal		**(31)**	(312)	(18)
State		**(21)**	(90)	(29)
		(52)	(402)	(47)
Total		**$ 337**	$ 438	$ 292

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

In millions December 31,	2007	2006
Deferred tax assets:		
Accrued charges	**$ 69**	$ 59
Investment tax credits	**62**	67
Property-related	**396**	408
Regulatory balancing accounts	**519**	496
Unrealized gains and losses	**393**	367
Decommissioning	**182**	167
Pensions and PBOPs	**177**	215
Other	**421**	358
Total	**$ 2,219**	$ 2,137
Deferred tax liabilities:		
Property-related	**$ 3,155**	$ 3,166
Capitalized software costs	**128**	147
Regulatory balancing accounts	**521**	393
Unrealized gains and losses	**394**	367
Decommissioning	**158**	140
Other	**273**	349
Total	**$ 4,629**	$ 4,562
Accumulated deferred income taxes – net	**$ 2,410**	$ 2,425
Classification of accumulated deferred income taxes – net:		
Included in deferred credits and other liabilities	**$ 2,556**	$ 2,675
Included in total current assets	**146**	250

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

Year ended December 31,	2007	2006	2005
Federal statutory rate	**35.0%**	35.0%	35.0%
Tax reserve adjustments	**(4.8)**	3.1	(2.1)
Resolution of state audit issue	**—**	(3.9)	—
Resolution of 1991-1993 audit cycle	**—**	—	(5.8)
Property-related	**(1.0)**	(0.3)	(0.5)
ESOP dividend payment	**(0.8)**	(0.9)	(1.0)
State tax – net of federal deduction	**4.4**	3.6	3.2
Other	**(2.0)**	(2.0)	(0.7)
Effective tax rate	**30.8%**	34.6%	28.1%

The composite federal and state statutory income tax rate was approximately 40% for all periods presented. The lower effective tax rate of 30.8% realized in 2007 was primarily due to reductions made to the income tax reserve to reflect progress in an administrative appeals process with the IRS related to SCE's income tax treatment of costs associated with environmental remediation and due to reductions made to the income tax reserve to reflect settlement of a state tax issue related to the April 2007 State Notice of Proposed Adjustment discussed below. The lower effective tax rate of 34.6% realized in 2006 was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue (see "California Apportionment ") partially offset by tax reserve accruals. The lower effective tax rate of 28.1% realized in 2005 was primarily due to settlement of the 1991-1993 IRS audit cycle as well as adjustments made to the tax reserve to reflect the issuance of new IRS regulations and the favorable settlement of other federal and state tax audit issues.

Accounting for Uncertainty in Income Taxes

Pursuant to the requirements of FIN 48, SCE records tax reserves for uncertain tax return positions reflected on filed tax returns. SCE also has filed affirmative tax claims for uncertain tax positions, reflecting potential refunds of taxes paid, or additional tax benefits for positions taken on prior tax returns. FIN 48 requires the disclosure of all unrecognized tax benefits, which includes the reserves recorded for uncertain 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, 2007 to December 31, 2007:

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

The unrecognized tax benefits in the table above reflects affirmative claims related to timing differences of $1.6 billion and $1.7 billion, at December 31, 2007 and January 1, 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 is vigorously defending these affirmative claims in IRS administrative appeals proceedings.

It is reasonably possible that Edison International could reach a settlement with the IRS to all or a portion of the unrecognized tax benefits through tax year 2002 within the next 12 months. SCE believes that that it is reasonably possible that unrecognized tax benefits could be reduced by an amount up to $1.3 billion within the next 12 months.

The total amount of unrecognized tax benefits as of December 31, 2007 and January 1, 2007 that, if recognized, would have an effective tax rate impact is $65 million and $35 million, respectively.

The total amount of accrued interest and penalties were $96 million and $65 million as of December 31, 2007 and January 1, 2007, respectively. In 2007, $24 million of after-tax interest income was recognized and included in income tax expense.

Tax Positions being addressed as part of active examinations and administrative appeals processes

Edison International and its subsidiaries remain subject to examination and administrative appeals by the IRS for tax years 1994 and forward. Edison International is challenging certain IRS deficiency adjustments for tax years 1994 – 1999 with the Administrative Appeals branch of the IRS and Edison International is currently under active IRS examination for tax years 2000 – 2002. 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 years.

In the examination phase for tax years 1994 – 1999, which is complete, the IRS asserted income tax deficiencies related to certain tax positions taken by Edison International on filed tax returns. Edison International is challenging the asserted tax deficiencies in IRS Appeals proceedings; however, most of the tax positions are timing differences and, therefore, any amounts that would be paid if Edison International's position is not sustained (exclusive of any penalties) would be deductible on future tax returns filed by Edison International. In addition, Edison International has filed affirmative claims with respect to certain tax years from 1986 through 2005 with the IRS and state tax authorities. Any benefits associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when SCE makes an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is consummated. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

In April 2007, Edison International received a Notice of Proposed Adjustment from the California Franchise Tax Board for tax years 2001 and 2002 and is currently protesting the deficiencies asserted. Edison International remains subject to examination by the California Franchise Tax Board for tax years 2003 and forward. Edison International is also subject to examination by other state tax authorities, with varying statute of limitations.

Balancing Account Over-Collections

In response to an affirmative claim related to balancing account over-collections, Edison International received an IRS Notice of Proposed Adjustment in July 2007. This affirmative claim is part of the ongoing IRS examinations and administrative appeals process and all of the tax years included in this Notice of Proposed Adjustment remain subject to ongoing examination and administrative appeals. The cash and earnings impacts of this position are dependent on the ultimate settlement of all open tax issues in these tax years. SCE expects that resolution of this particular issue could potentially increase earnings and cash flow within the range of $70 million to $80 million and $300 million to $325 million, respectively.

Contingent Liability Company

The IRS has asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company for tax years 1997 – 1998. This is being considered by the Administrative Appeals branch of the IRS where Edison International is defending its tax return position with respect to this transaction.

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.

Resolution of Federal and State Income Tax Issues Being Addressed in Ongoing Examinations and Administrative Appeals

In 2008, Edison International will continue its efforts to resolve open tax issues through tax year 2002. 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 $61 million in 2007, $57 million in 2006 and $51 million in 2005.

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. 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. Upon adoption, SCE recorded additional postretirement benefit assets of $145 million, additional postretirement liabilities of $320 million (including $24 million classified as current), additional regulatory assets of $303 million, regulatory liabilities of $145 million, and a reduction to accumulated other comprehensive income (loss) (a component of shareholders' equity) of $10 million, net of tax.

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 $44 million for the year ending December 31, 2008. This amount is subject to change based on the funded status at year-end and the tax deductible limitations.

The fair value of the plan assets is determined primarily by quoted market prices.

Information on plan assets and benefit obligations is shown below:

In millions **Year ended December 31,**	**2007**	**2006**
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 3,176**	$ 3,222
Service cost	**100**	102
Interest cost	**171**	169
Amendments	**(5)**	12
Actuarial gain	**(90)**	(66)
Special termination benefits	**2**	8
Benefits paid	**(248)**	(271)
Projected benefit obligation at end of year	**$ 3,106**	$ 3,176
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 3,340**	$ 3,103
Actual return on plan assets	**284**	473
Employer contributions	**83**	35
Benefits paid	**(248)**	(271)
Fair value of plan assets at end of year	**$ 3,459**	$ 3,340
Funded status at end of year	**$ 353**	$ 164
Amounts recognized in the consolidated balance sheets consist of:		
Long-term assets	**$ 445**	$ 247
Current liabilities	**(5)**	(5)
Long-term liabilities	**(87)**	(78)
	$ 353	$ 164
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	**$ 1**	$ 2
Net loss	**24**	22
	$ 25	$ 24
Additional detail of amounts recognized as a regulatory liability:		
Prior service cost	**$ 49**	$ 71
Net gain	**$ (357)**	$ (215)
Accumulated benefit obligation at end of year	**$ 2,773**	$ 2,782
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 92**	$ 82
Accumulated benefit obligation	**$ 75**	$ 67
Fair value of plan assets	**—**	—
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	**6.25%**	5.75%
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,	2007	2006	2005
Service cost	**$ 100**	$ 102	$ 99
Interest cost	**171**	169	166
Expected return on plan assets	**(237)**	(225)	(215)
Special termination benefits	**2**	8	—
Amortization of transition obligation	**—**	—	1
Amortization of prior service cost	**17**	16	16
Amortization of net loss	**3**	3	4
Expense under accounting standards	**$ 56**	$ 73	$ 71
Regulatory adjustment – deferred	**(3)**	(10)	(26)
Total expense recognized	**$ 53**	$ 63	$ 45

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

In millions Year ended December 31,	2007
Net loss	**$ 5**
Prior service cost	**—**
Amortization of prior service cost	**—**
Amortization of net gain	**(3)**
Total recognized in other comprehensive income	**$ 2**
Total recognized in expense and other comprehensive income	**$ 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 2008 are $17 million for prior service cost and $(2) 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,	2007	2006	2005
Weighted-average assumptions:			
Discount rate	**5.75%**	5.5%	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,**
2008	$ 264
2009	$ 271
2010	$ 279
2011	$ 292
2012	$ 298
2013 – 2017	$ 1,484

The following are asset allocations by investment category:

	Target for 2008	**December 31, 2007**	**2006**
United States equities	45%	**47%**	47%
Non-United States equities	25%	**25%**	26%
Private equities	4%	**2%**	2%
Fixed income	26%	**26%**	25%

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 $40 million for the year ending December 31, 2008. This amount is subject to change based on the funded status at year-end and the tax deductible limitations.

The fair value of plan assets is determined primarily by quoted market prices.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2007	2006
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,178**	$ 2,275
Service cost	**43**	43
Interest cost	**125**	116
Amendments	**6**	—
Actuarial gain	**(77)**	(159)
Special termination benefits	**1**	4
Plan participants' contributions	**8**	7
Medicare Part D subsidy received	**4**	3
Benefits paid	**(106)**	(111)
Benefit obligation at end of year	**$ 2,182**	$ 2,178
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,743**	$ 1,573
Actual return on assets	**117**	203
Employer contributions	**49**	68
Plan participants' contributions	**8**	7
Medicare Part D subsidy received	**4**	3
Benefits paid	**(106)**	(111)
Fair value of plan assets at end of year	**$ 1,815**	$ 1,743
Fund status at end of year	**$ (367)**	$ (435)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	**$ (18)**	$ (19)
Long-term liabilities	**(349)**	(416)
	$ (367)	$ (435)
Amounts recognized in accumulated other comprehensive loss (income) consist of:		
Prior service cost	**$ —**	$ —
Net loss	**—**	—
	$ —	$ —
Additional detail of amounts recognized as a regulatory asset:		
Prior service cost (credit)	**$ (206)**	$ (242)
Net actuarial loss	**$ 437**	$ 545
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	**6.25%**	5.75%
Assumed health care cost trend rates:		
Rate assumed for following year	**9.25%**	9.25%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2015**	2011

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

In millions Year ended December 31,	2007	2006	2005
Service cost	**$ 43**	$ 43	$ 44
Interest cost	**125**	116	118
Expected return on plan assets	**(119)**	(106)	(101)
Special termination benefits	**1**	4	—
Amortization of prior service cost (credit)	**(29)**	(29)	(28)
Amortization of net loss	**28**	41	45
Total expense	**$ 49**	$ 69	$ 78

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

In millions Year ended December 31,	2007
Net loss (gain)	**$ —**
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	**$ 49**

Effective with the adoption of SFAS No. 158, as of December 31, 2006, 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, in accordance with SFAS No. 71. The estimated amortization amounts for 2008 are $(29) million for prior service cost (credit) and $16 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,	2007	2006	2005
Discount rate	**5.75%**	5.5%	5.75%
Expected return on plan assets	**7.0%**	7.0%	7.1%
Assumed health care cost trend rates:			
Current year	**9.25%**	10.25%	10.0%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2015**	2011	2010

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2007 by $259 million and annual aggregate service and interest costs by $18 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2007 by $231 million and annual aggregate service and interest costs by $16 million.

The following benefit payments are expected to be paid:

In millions	Year ending December 31,	Before Subsidy*	Net
2008		$ 102	$ 97
2009		110	104
2010		118	111
2011		128	121
2012		137	129
2013 – 2017		803	747

* Medicare Part D prescription drug benefits

The following are asset allocations by investment category:

Asset allocations are:

	Target for 2008	December 31, 2007	December 31, 2006
United States equities	64%	**62%**	64%
Non-United States equities	16%	**14%**	13%
Fixed income	20%	**24%**	23%

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. SCE employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is controlled 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 5%. 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 for United States Plans

The overall expected long term rate of return on assets assumption is based on the 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

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 nongovernment bonds in the broad fixed income market. The equilibrium yield is based on analysis of historic 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 is estimated to be a 3% premium over the estimated total return of intermediate United States government bonds. This value is determined by combining estimates of real earnings growth, dividend yields and inflation, each of which was determined using historical analysis. 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

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 and $20 million for 2007 and 2006, respectively. Under prior accounting rules, there was no comparable expense recognized for the same period in 2005. 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 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,	2007	2006	2005
Expected terms (in years)	**7.5**	9 to 10	9 to 10
Risk-free interest rate	**4.6% – 4.8%**	4.3% – 4.7%	4.1% – 4.3%
Expected dividend yield	**2.1% – 2.4%**	2.3% – 2.8%	2.1% – 3.1%
Weighted-average expected dividend yield	**2.4%**	2.4%	3.1%
Expected volatility	**16% – 17%**	16% – 17%	15% – 20%
Weighted-average volatility	**16.5%**	16.3%	19.5%

The expected term represents the period of time for which the options are expected to be outstanding and is primarily based on historical exercise and post vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a 52-week historical average of the 10-year semi-annual coupon U.S. Treasury note. In 2007 and 2006, expected volatility is based on the historical volatility of Edison International's common stock for the most recent 36 months. Prior to January 1, 2006, expected volatility was based on the median of the most recent 36 months historical volatility of peer companies because Edison International's historical volatility was impacted by the California energy crisis.

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, 2006	7,761,336	$ 26.78		
Granted	935,218	$ 47.77		
Expired	—	—		
Forfeited	(40,191)	$ 41.20		
Exercised	(2,395,979)	$ 23.21		
Outstanding at December 31, 2007	**6,260,384**	**$ 31.21**	**6.49**	
Vested and expected to vest at December 31, 2007	5,983,218	$ 30.86	6.43	$129,191,430
Exercisable at December 31, 2007	**2,978,568**	**$ 23.66**	**5.20**	**$ 85,759,823**

The weighted-average grant-date fair value of options granted during the 2007, 2006 and 2005 was $11.36, $14.42 and $11.76, respectively. The total intrinsic value of options exercised during 2007, 2006 and 2005 was $69 million, $43 million and $42 million, respectively. At December 31, 2007, there was $14 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 2007, 2006, and 2005 was $14 million, $27 million and $16 million, respectively.

The amount of cash used to settle stock options exercised was $125 million, $88 million and $95 million for 2007, 2006, and 2005, respectively. Cash received from options exercised for 2007, 2006 and 2005 was $56 million, $45 million and $53 million, respectively. The estimated tax benefit from options exercised for 2007, 2006 and 2005 was $28 million, $17 million and $17 million.

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units, payable in shares of Edison International common stock. Approximately three options were cancelled for each deferred stock unit issued. The deferred stock units vested, and were settled, 25% in each of the ensuing 12-month periods. Cash used to settle deferred stock units in 2005 was $11 million.

Performance Shares

A target number of contingent performance shares were awarded to executives in January 2005, March 2006 and March 2007, and vest at the end of December 2007, 2008 and 2009, 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 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 $6 million, $7 million and $31 million for 2007, 2006, and 2005, respectively. The amount of cash used to settle performance shares classified as equity awards was $11 million, $19 million and $10 million for 2007, 2006 and 2005, 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 semi-annual coupon U.S. Treasury note 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 2007, 2006 and 2005 performance shares classified as share-based equity awards was 4.8%, 4.1% and 2.7%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2007, 2006 and 2005 performance shares classified as share-based equity awards was 16.5%, 16.2% and 27.7%, 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, 2007 was 4.3% and 17.1%, respectively. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2006 was 4.8% and 16.5%, respectively.

The total intrinsic value of performance shares settled during 2007, 2006 and 2005 was $23 million, $38 million and $21 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2007, 2006 and 2005 of $5 million, $9 million and $5 million, respectively. At December 31, 2007, there was $3 million (based on the December 31, 2007 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 2007, 2006 and 2005 were $8 million, $14 million and $21 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, 2006	108,604	$ 48.96
Granted	39,032	$ 57.70
Forfeited	(741)	$ 56.77
Paid out	(61,652)	$ 46.09
Nonvested at December 31, 2007	**85,243**	**$ 55.01**

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2006 and 2005 was $52.76 and $46.09, 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, 2006	108,727	
Granted	39,116	
Forfeited	(745)	
Paid out	(61,711)	
Nonvested at December 31, 2007	**85,387**	**$ 44.50**

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. 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. The fair value changes for these power purchase contracts were previously recorded in purchased-power expense and offset through the provisions for regulatory adjustment clauses – net; therefore, 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, 2007, the net liability was $59 million. At December 31, 2007, SCE had 67 power contracts classified as operating leases. Operating lease expense for power purchases was $297 million in 2007, $188 million in 2006, and $68 million in 2005. In addition, SCE executed a power purchase contract in late 2005 and an additional power purchase contract in June 2007 which met the requirements for capital leases. These capital leases have a net commitment of $20 million at December 31, 2007 and $13 million at December 31, 2006. SCE's capital lease executory costs and interest expense was $2 million in 2007 and $3 million in 2006.

Other operating lease expense, primarily for vehicle leases, was $39 million in 2007, $31 million in 2006 and $20 million in 2005. 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**
2008		$ 566	$ 52
2009		647	50
2010		610	45
2011		400	36
2012		240	29
Thereafter		1,414	101
Total		$ 3,877	$ 313

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 $2.8 billion as of December 31, 2007, 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 effective January 2007, 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 is 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 ($89 million at December 31, 2007). Total expenditures for the decommissioning of San Onofre Unit 1 were $538 million from the beginning of the project in 1998 through December 31, 2007.

Decommissioning expense under the rate-making method was $131 million, $161 million and $118 million in 2007, 2006 and 2005, respectively. The ARO for decommissioning SCE's active nuclear facilities was $2.7 billion and $2.6 billion at December 31, 2007 and 2006, respectively.

Decommissioning funds collected in rates are placed in independent trusts, which, 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:

		December 31,	
In millions	Maturity Dates	2007	2006
Municipal bonds	2008 – 2044	**$ 561**	$ 692
Stocks	–	**1,968**	1,611
United States government issues	2008 – 2049	**552**	729
Corporate bonds	2008 – 2047	**241**	104
Short-term	2008	**56**	48
Total		**$ 3,378**	$ 3,184

Note: Maturity dates as of December 31, 2007.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings were $143 million, $130 million and $87 million in 2007, 2006 and 2005, respectively. Proceeds from sales of securities (which are reinvested) were $3.3 billion, $3.0 billion and $2.0 billion in 2007, 2006 and 2005, respectively. Unrealized holding gains, net of losses, were $1.1 billion, $1.0 billion and $ 852 million at December 31, 2007, 2006 and 2005, respectively. Realized losses for other-than-temporary impairments were $58 million and $54 million for the year ended December 31, 2007 and 2006, respectively. Approximately 92% of the cumulative trust fund contributions were tax-deductible.

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 purchased-power 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 2008 through 2012 are estimated below:

In millions	2008	2009	2010	2011	2012
Fuel supply	$ 101	$ 79	$ 71	$ 68	$ 64
Purchased power	$ 410	$324	$294	$290	$339

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 $53 million through 2016 (approximately $6 million per year).

Indemnities

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the 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, 2007, SCE's recorded estimated minimum liability to remediate its 24 identified sites was $66 million, of which $31 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 $147 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 $34 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $64 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 $25 million, $14 million and $13 million for 2007, 2006 and 2005, 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.

FERC Refund Proceedings

SCE is participating in several related proceedings seeking recovery of refunds 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, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

On August 2, 2006, the Ninth Circuit issued an opinion regarding the scope of refunds issued by the FERC. The Ninth Circuit broadened the time period during which refunds could be ordered to include the summer of 2000 based on evidence of pervasive tariff violations and broadened the categories of transactions that could be subject to refund. As a result of this decision, SCE may be able to recover additional refunds from sellers of electricity during the crisis with whom settlements have not been reached.

During the course of the refund proceedings, the FERC ruled that governmental power sellers, like private generators and marketers that sold into the California market, should refund the excessive prices they received during the crisis period. However, in late 2005, the Ninth Circuit ruled in Bonneville Power Admin v. FERC that the FERC does not have authority directly to enforce its refund orders against governmental power sellers. The Court, however, clarified that its decision does not preclude SCE or other parties from pursuing civil claims or refunds against the governmental power sellers.

In March 2007, SCE, PG&E and the Oversight Board filed claims in the U.S. Court of Federal Claims against two federal agencies that sold power into California during the energy crisis. On February 7, 2008, the federal agencies filed a motion to dismiss the case. The Court's ruling on the motion is expected in the second half of 2008. In April 2007, SCE, along with PG&E, the Oversight Board and SDG&E, filed claims for refunds against several non-federal governmental power sellers in the Los Angeles Superior Court.

In October 2007, the FERC issued an order on remand from the Ninth Circuit's Bonneville decision, in which it concluded that the decision required the FERC to vacate its previous orders compelling governmental sellers during the California energy crisis to pay refunds. Based on this conclusion, the FERC also ordered the release of the amounts that had been withheld from governmental sellers as well as any collateral posted by the sellers for power delivered by them during the energy crisis. In its order, the FERC also expressly recognized that civil lawsuits against the governmental sellers could provide an alternative refund remedy for SCE and the other California utilities. It also left open the possibility that a court could order the ISO or PX to retain collateral. SCE cannot predict at this time the ultimate impact of the FERC's orders on SCE's ability to recover refunds from governmental power sellers through the pending lawsuits.

In November 2005, SCE and other parties entered into a settlement agreement with Enron Corporation and a number of its affiliates, most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In 2006 and 2007, SCE received distributions of approximately $55 million and $24 million, respectively, on its allowed bankruptcy claim. Additional distributions are expected but SCE cannot currently predict the amount or timing of such distributions.

Investigations Regarding Performance Incentives Rewards

SCE was eligible under its CPUC-approved PBR mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability. SCE conducted investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million over the period 1997 – 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of approximately $10 million for 2003.

Following its internal investigation, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forgo an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997 – 2003). In addition, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading.

SCE has taken remedial action as to the customer satisfaction survey misconduct by disciplining employees and/or terminating certain employees, including several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 GRC.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE conducted an investigation into the accuracy of SCE's employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has recognized $20 million in employee safety incentives for 1997 through 2000 and, based on SCE's records, may be entitled to an additional $15 million for 2001 through 2003.

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. SCE disclosed in the investigative findings to the CPUC that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism and return to ratepayers the $20 million it has already received. SCE has also proposed to withdraw the pending rewards for the 2001 – 2003 time frames.

SCE has taken remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance, disciplining employees who committed wrongdoing and terminating one employee. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE conducted an investigation into the third PBR metric, system reliability for the years 1997 – 2003. SCE received $8 million in reliability incentive awards for the period 1997 – 2000 and applied for a reward of $5 million for 2001. For 2002, SCE's data indicated that it earned no reward and incurred no penalty. For 2003, based on the application of the PBR mechanism, it would incur a penalty of $3 million and accrued a charge for that amount in 2004. On February 28, 2005, SCE provided its final investigation report to the CPUC concluding that the reliability reporting system was working as intended.

CPUC Investigation

On June 15, 2006, the CPUC instituted a formal investigation to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, employee safety and system reliability portions of PBR. In June 2006, the CPSD of the CPUC issued its report regarding SCE's PBR program, recommending that the CPUC impose various refunds and penalties on SCE. Subsequently, in September 2006, the CPSD and other intervenors, such as the CPUC's DRA and The Utility Reform Network, filed testimony on these matters recommending various refunds and penalties be imposed on SCE. In their testimony, the various parties made refund and penalty recommendations that range up to the following amounts: refund or forgo $48 million in rewards for customer satisfaction, impose $70 million penalties for customer satisfaction, refund or forgo $35 million in rewards for employee safety, impose $35 million penalties for employee safety, impose $102 million in statutory penalties, refund $84 million related to amounts collected in rates for employee bonuses ("results sharing"), refund $4 million of miscellaneous survey expenses, and require $10 million of new employee safety programs. These recommendations total up to $388 million. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors.

On October 1, 2007, a POD was released ordering SCE to refund $136 million, before interest, and pay a statutory penalty of $40 million. Included in the amount to be refunded are $28 million related to customer satisfaction rewards, $20 million related to employee safety rewards, and $77 million related to results sharing. The decision requires that the proposed results sharing refund of $77 million (based on year 2000 data) be adjusted for attrition and escalation which increases the results sharing refund to $88 million. Interest as of December 31, 2007, based on amounts collected for customer satisfaction, employee safety incentives and results sharing, including escalation and attrition adjustments, would add an additional $28 million to this amount. The POD also requires SCE to forgo $35 million in rewards for which it would have otherwise been eligible. Included in the amount to be forgone is $20 million related to customer satisfaction rewards and $15 million related to employee safety rewards.

On October 31, 2007, SCE appealed the POD to the CPUC. The CPSD and an intervenor also filed appeals. The CPSD appeal requested that: (1) the statutory penalty be increased from $40 million to $83 million (2) a penalty be imposed under the PBR customer satisfaction and employee safety mechanisms in the amount of $48 million and $35 million, respectively, and (3) SCE refund/forgo rewards earned under the customer satisfaction and employee safety mechanisms of $48 million and $35 million, respectively. The appealing intervenor asked that the statutory penalty be increased to as much as $102 million. Oral argument on the appeals took place on January 30, 2008, and it is uncertain when the CPUC will issue a decision.

SCE cannot predict the outcome of the appeal. Based on SCE's proposed refunds, the combined recommendations of the CPSD and other intervenors, as well as the POD, the potential refunds and penalties could range from $52 million up to $388 million. SCE has recorded an accrual at the lower end of this range of potential loss and is accruing interest (approximately $16 million as of December 31, 2007) on collected amounts.

The system reliability component of PBR was not addressed in the POD. Pursuant to an earlier order in the case, system reliability incentives will be addressed in a second phase of the proceeding, which commenced with the filing of SCE's opening testimony in September 2007. In that testimony, SCE confirmed that its PBR system reliability results, which reflected rewards of $13 million for 1997 through 2002 and a penalty of $3 million in 2003, were valid. An indefinite suspension of the schedule for the second phase of the proceeding pending resolution of the appeals of the POD has been granted. SCE cannot predict the outcome of the second phase.

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 order reversed an arbitrator's award that had affirmed the ISO's characterization in May 2000 of the charges as Intra-Zonal Congestion costs and allocation of those charges to scheduling coordinators in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from scheduling coordinators in the affected zone to the responsible participating transmission owner, SCE. The potential cost to SCE, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the time, is estimated to be approximately $20 million to $25 million, including interest. On April 20, 2005, the FERC stayed its April 20, 2004 order during the pendency of SCE's appeal filed with the Court of Appeals for the D.C. Circuit. On March 7, 2006, the Court of Appeals remanded the case back to the FERC at the FERC's request and with SCE's consent. On March 29, 2007, the FERC issued an order agreeing with SCE's position that the charges incurred by the ISO were related to voltage support and should be allocated to the scheduling coordinators, rather than to SCE as a transmission owner. The Cities filed a request for rehearing of the FERC's order on April 27, 2007. On May 25, 2007, the FERC issued a procedural order granting the rehearing application for the limited purpose of allowing the FERC to give it further consideration. In a future order, FERC may deny the rehearing request or grant the requested relief in whole or in part. SCE believes that the most recent substantive FERC order 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.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in Midway-Sunset, which owns a 225 MW cogeneration facility near Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC because Midway-Sunset was a seller in the PX market during 2000 and 2001, both for its own account and on behalf of SCE and PG&E, the utilities to which the majority of Midway-Sunset's power was contracted for sale. As a seller into the PX market, Midway-Sunset is potentially liable for refunds to purchasers in these markets.

The claims asserted against Midway-Sunset for refunds related to power sold into the PX market, including power sold on behalf of SCE and PG&E, are estimated to be less than $70 million for all periods under consideration. Midway-Sunset did not retain any proceeds from power sold into the PX market on behalf of SCE and PG&E in excess of the amounts to which it was entitled under the pre-existing power sales contracts, but instead passed through those proceeds to the utilities. Since the proceeds were passed through to the utilities, EME believes that PG&E and SCE are obligated to reimburse Midway-Sunset for any refund liability that it incurs as a result of sales made into the PX market on their behalves.

On December 20, 2007, Midway-Sunset entered into a settlement agreement with SCE, PG&E, SDG&E and certain California state parties to resolve Midway-Sunset's liability in the FERC refund proceedings. Midway-Sunset concurrently entered into a separate agreement with SCE and PG&E that provides for pro-rata reimbursement to Midway-Sunset by the two utilities of the portions of the agreed to refunds that are attributable to sales made by Midway-Sunset for the benefit of the utilities. The settlement has been approved by the CPUC but remains subject to approval by the FERC.

During the period in which Midway-Sunset's generation was sold into the PX market, amounts SCE received from Midway-Sunset for its pro-rata share of such sales were credited to SCE's customers against power purchase expenses through the ratemaking mechanism in place at that time. SCE believes that any net amounts reimbursed to Midway-Sunset would be recoverable from its customers through current regulatory mechanisms. SCE does not expect any reimbursement to Midway-Sunset to have a material impact on earnings.

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. In April 2004, the District Court denied SCE's motion for summary judgment and concluded that a 2003 U.S. Supreme Court decision in an on-going related lawsuit by the Navajo Nation against the U.S. Government did not preclude the Navajo Nation from pursuing its RICO and intentional tort claims. In September 2007, the Federal Circuit reversed a lower court decision on remand in the related lawsuit, finding that the U.S. Government had breached its trust obligation in connection with the setting of the royalty rate for the coal supplied to Mohave. Subsequently, the Federal Circuit denied the U.S. Government's petition for rehearing. The U.S. Government may, however, still seek review by the Supreme Court of the Federal Circuit's September decision.

Pursuant to a joint request of the parties, the District Court granted a stay of the action in October 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. In a joint status report filed on November 9, 2007, the parties informed the court that their mediation efforts had terminated and subsequently filed a joint motion to lift the stay. The parties have also filed recommendations for a scheduling order to govern the anticipated resumption of litigation. The Court has not yet ruled on either the motion to lift the stay or the scheduling recommendations, but has scheduled a status hearing for March 6, 2008. SCE cannot predict the outcome of the Navajo Nation's and Hopi Tribe's complaints against SCE or the ultimate impact on these complaints of the Supreme Court's 2003 decision and 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 $10.8 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. The current maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than $15 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 will be adjusted for inflation on a 5-year schedule. The next inflation adjustment will occur no later than August 20, 2008. Based on its ownership interests, SCE could be required to pay a maximum of $201 million per nuclear incident. However, it would have to pay no more than $30 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 regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

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 $46 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. A follow-up to the first inspection resulted in a finding that Palo Verde had not established adequate measures to ensure that certain corrective actions were effective to address the reduction in the ability to cool water before returning it to the plant. The second inspection identified five violations, but none of those resulted in increased NRC scrutiny. The third inspection, concerning the failure of an emergency backup generator at Palo Verde Unit 3 identified a violation that, combined with the first inspection finding, will cause the NRC to undertake additional oversight inspections of Palo Verde. In addition, Palo Verde will be 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. These corrective actions are currently being developed in conjunction with the NRC, and are forecast to be completed and embodied in an NRC Confirmatory Order by the end of February 2008. These corrective actions will increase costs to both Palo Verde and its co-owners, including SCE. SCE cannot calculate the total increase in costs until the corrective actions are finalized and the NRC issues the Confirmatory Order. The operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE presently estimates that operation and maintenance costs will increase by approximately $23 million (nominal) over the two year period 2008 – 2009, from 2007 recorded costs including overhead costs. SCE also is unable to estimate how long SCE will continue to incur these costs.

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.

In March 2007, SCE successfully challenged the CPUC's calculation of SCE's annual targets. This change is expected to enable SCE to meet its target for 2007. On April 3, 2007, SCE filed its renewable portfolio standard compliance report for 2004 through 2006. The compliance report confirms that SCE met its renewable goals for each of these years. In light of the annual target revisions that resulted from the March 2007 successful challenge to the CPUC's calculation, the report also projects that SCE will meet its renewable goals for 2007 and 2008 but could have a potential deficit in 2009. The potential deficit in 2009, however, does not take into account future procurement opportunities or the full utilization by SCE of the CPUC's rules for flexible compliance with annual targets. 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.

SCE is scheduled to update the compliance report discussed above in March 2008, and currently anticipates demonstrating full compliance for the procurement year 2007 as well as forecasting full compliance, with the use of flexible compliance rules, for the procurement year 2008. 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 failure 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 failing to achieve renewable procurement targets is $25 million per year. SCE cannot predict whether it will be assessed penalties.

Scheduling Coordinator Tariff Dispute

Pursuant to the Amended and Restated Exchange Agreement, SCE serves as a scheduling coordinator for the DWP over the ISO-controlled grid. In late 2003, SCE began charging the DWP under a tariff subject to refund for FERC-authorized scheduling coordinator and line loss charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges had been billed to the DWP under a FERC tariff that was subject to dispute. The DWP has paid the amounts billed under protest but requested that the FERC declare that SCE was obligated to serve as the DWP's scheduling coordinator without charge. The FERC accepted SCE's tariff for filing, but held that the rates charged to the DWP have not been shown to be just and reasonable and thus made them subject to refund and further review by the FERC.

In January 2008, an agreement between SCE and the DWP was executed settling the dispute discussed above. The settlement had been previously approved by the FERC in July 2007. The settlement agreement provides that the DWP will be responsible for line losses and SCE would be responsible for the scheduling coordinator charges. During the fourth quarter of 2007, SCE reversed and recognized in earnings (under the caption "Purchased power" in the consolidated statements of income) $30 million of an accrued liability representing line losses previously collected from the DWP that were subject to refund. As of December 31, 2007, SCE had an accrued liability of approximately $22 million (including $3 million of interest) representing the estimated amount SCE will refund for scheduling coordinator charges previously collected from the DWP. SCE made its first refund payment on February 20, 2008 and the second refund payment is due on March 15, 2008. SCE previously received FERC-approval to recover the scheduling coordinator charges from all transmission grid customers through SCE's transmission rates and on December 11, 2007 the FERC accepted SCE's proposed transmission rates reflecting the forecast levels of costs associated with the settlement. Upon signing of the agreement in January 2008, SCE recorded a regulatory asset and recognized in earnings the amount of scheduling coordinator charges to be collected through rates.

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 obligation to begin acceptance of spent nuclear fuel not later than 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 through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the 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. The case was stayed through April 7, 2006, when SCE and the DOE filed a Joint Status Report in which SCE sought to lift the stay and the government opposed lifting the stay. On June 5, 2006, the Court of Federal Claims lifted the stay on SCE's case and established a discovery schedule. A Joint Status Report was filed on February 22, 2008, regarding further proceedings in this case and presumably including establishing a trial date.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation where all of Unit 1's spent fuel located at San Onofre and some of Unit 2's spent fuel is stored. SCE, as operating agent, plans to transfer fuel from the Unit 2 and 3 spent fuel pools to the independent storage installation on an as-needed basis to maintain full core off-load capability for Units 2 and 3. There are now sufficient dry casks and modules available at the independent spent fuel storage installation to meet plant requirements through 2008. SCE plans to add storage capacity incrementally to meet the plant requirements until 2022 (the end of the current NRC operating license).

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed an independent spent fuel storage facility. Arizona Public Service, as operating agent, plans to add storage capacity incrementally to maintain full core off-load capability for all three units.

Note 7. Accumulated Other Comprehensive Loss Information

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

	Unrealized Gain (Loss) on Cash Flow Hedges	Minimum Pension Liability Adjustment	Pension and PBOP – Net Loss	Pension and PBOP – Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2005	$ (5)	$ (11)	$ —	$ —	$ (16)
Change for 2006	5	—	—	—	5
SFAS No. 158 adjustments	—	11	(13)	(1)	(3)
Balance at December 31, 2006	—	—	(13)	(1)	(14)
Change for 2007	—	—	(1)	—	(1)
Balance at December 31, 2007	**$ —**	**$ —**	**$ (14)**	**$ (1)**	**$ (15)**

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,	2007	2006
Furniture and equipment	**$ 4**	$ 4
Building, plant and equipment	**1,657**	1,639
Land (including easements)	**35**	34
Construction in progress	**5**	2
	1,701	1,679
Accumulated provision for depreciation	**(701)**	(633)
Nonutility property – net	**$ 1,000**	$ 1,046

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 $3.4 billion at December 31, 2007. For a further discussion about nuclear decommissioning see "Nuclear Decommissioning Commitment" in Note 6.

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

In millions	2007	2006	2005
Beginning balance	**$ 2,749**	$ 2,621	$ 2,183
Accretion expense	**168**	160	366
Revisions	**3**	(3)	117
Liabilities added	**—**	41	14
Liabilities settled	**(43)**	(70)	(59)
Ending balance	**$ 2,877**	$ 2,749	$ 2,621

The ARO liability as of December 31, 2007 includes an ARO liability of $2.8 billion related to nuclear decommissioning

In March 2005, the FASB issued FIN 47, which clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. FIN 47 was effective as of December 31, 2005. Since SCE follows SFAS No. 71 and receives recovery of these costs through rates; therefore, SCE's implementation of FIN 47 did not affect SCE's earnings. The pro forma disclosures related to adoption of FIN 47 are not shown due to the immaterial impact on SCE's consolidated balance sheet.

Note 9. Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions **Year ended December 31,**	2007	2006	2005
Cash payments for interest and taxes:			
Interest — net of amounts capitalized	**$ 292**	$ 321	$ 330
Tax payments — net	**$ 299**	$ 832	$ 410
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	**$ —**	$ (331)	$ (452)
Pollution-control bonds issued	**$ —**	$ 331	$ 452
Details of obligation under capital leases:			
Capital lease purchased	**$ (10)**	$ —	$ (15)
Capital lease obligation issued	**$ 10**	$ —	$ 15
Dividends declared but not paid:			
Common stock	**$ 25**	$ 60	$ 71
Preferred and preference stock not subject to mandatory redemption	**$ 13**	$ 9	$ 10

Note 10. Fair Values of Financial Instruments

The carrying amounts and fair values of financial instruments are:

	December 31,			
	2007		2006	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Interest rate hedges	**$ (33)**	**$ (33)**	$ —	$ —
Commodity price assets	**82**	**82**	50	50
Commodity price liabilities	**(77)**	**(77)**	(160)	(160)
Other:				
Decommissioning trusts	**3,378**	**3,378**	3,184	3,184
QF power contracts liabilities	**(3)**	**(3)**	(2)	(2)
Long-term debt	**(5,081)**	**(5,100)**	(5,171)	(5,206)
Long-term debt due within one year	**—**	**—**	(396)	(398)

Fair values are based on: brokers' quotes for interest rate hedges, long-term debt and preferred stock; financial models for commodity price derivatives and QF power contracts; and quoted market prices for decommissioning trusts.

Due to their short maturities, amounts reported for cash equivalents approximate fair value.

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 expects to amortize and recover 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 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, except for regulatory balancing accounts, which are offset through the "Provisions for regulatory adjustments clauses – net" account.

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

In millions	December 31,	2007	2006
Current:			
Regulatory balancing accounts		**$ 99**	$ 128
Rate reduction notes – transition cost deferral		**—**	219
Direct access procurement charges		**—**	63
Energy derivatives		**71**	88
Purchased-power settlements		**8**	31
Deferred FTR proceeds		**15**	14
Other		**4**	11
		$ 197	$ 554
Long-term:			
Regulatory balancing accounts		**15**	—
Flow-through taxes – net		**1,110**	1,023
Unamortized nuclear investment – net		**405**	435
Nuclear-related ARO investment – net		**297**	317
Unamortized coal plant investment – net		**94**	102
Unamortized loss on reacquired debt		**331**	318
SFAS No. 158 pensions and other postretirement benefits		**231**	303
Energy derivatives		**70**	145
Environmental remediation		**64**	77
Other		**104**	98
		$ 2,721	$ 2,818
Total Regulatory Assets		**$ 2,918**	$ 3,372

SCE's regulatory asset related to the rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and was recovered in 2007. SCE's regulatory assets related to direct access procurement charges are for amounts direct access customers owe bundled service customers for the period May 1, 2000 through August 31, 2001, and are offset by corresponding regulatory liabilities to the bundled service customers. These amounts were collected as of September 30, 2007. 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 will be recovered through October 2008. SCE's regulatory assets related to deferred FTR proceeds represent the deferral of congestion revenue SCE received as a transmission owner from the annual ISO FTR auction. The deferred FTR proceeds will be recognized through March 2008. 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 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.

In 2007, SCE earned 8.77% return on both of the regulatory assets listed above: unamortized nuclear investment – net and unamortized coal plant investment – net.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

In millions December 31,	2007	2006
Current:		
Regulatory balancing accounts	**$ 967**	$ 912
Rate reduction notes – transition cost overcollection	**20**	—
Direct access procurement charges	**—**	63
Energy derivatives	**10**	7
Deferred FTR costs	**19**	11
Other	**3**	7
	$ 1,019	$ 1,000
Long-term:		
ARO	**793**	732
Costs of removal	**2,230**	2,158
SFAS No. 158 pensions and other postretirement benefits	**308**	145
Energy derivatives	**27**	27
Employee benefit plans	**75**	78
	$ 3,433	$ 3,140
Total Regulatory Liabilities	**$ 4,452**	$ 4,140

Rate reduction notes – transition cost overcollection represents the nonbypassable rates being charged to customers subsequent to the final principal payment made in December 2007. SCE's regulatory liabilities related to direct access procurement charges are a liability to its bundled service customers and are offset by regulatory assets from direct access customers. 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 2008. 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 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. All the amounts will be refunded to ratepayers. (see "Long-Term Debt" discussion in Note 3 for further detail).

Note 12. Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions **Year ended December 31,**	**2007**	**2006**	**2005**
AFUDC	**$ 46**	$ 32	$ 25
Increase in cash surrender value of life insurance policies	**23**	21	18
Performance-based incentive awards	**4**	19	33
Demand-side management and energy efficiency performance incentives	**—**	—	45
Other	**16**	13	6
Total other nonoperating income	**$ 89**	$ 85	$ 127
Various penalties	**$ 5**	$ 23	$ 27
Other	**40**	37	38
Total other nonoperating deductions	**$ 45**	$ 60	$ 65

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, 2007:

In millions	**Investment in Facility**	**Accumulated Depreciation and Amortization**	**Ownership Interest**
Transmission systems:			
Eldorado	$ 71	$ 12	60%
Pacific Intertie	308	96	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	529	435	48
Mohave (coal)	344	283	56
Palo Verde (nuclear)	1,800	1,490	16
San Onofre (nuclear)	4,722	4,001	78
Total	**$ 7,774**	**$ 6,317**	

All of Mohave Generating Station 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

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 a new accounting standard, SCE consolidated these four projects.

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, 2008, these projects sell power to SCE under agreements with pricing set by the CPUC.

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.

SCE also has eight other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under the new accounting 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 267 MW. SCE paid $180 million in both 2007 and 2006 and $198 million in 2005 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, 2007, 2006 and 2005. 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, 2007 Shares Outstanding	December 31, 2007 Redemption Price	2007	2006
Cumulative preferred stock:				
$25 par value:				
4.08% Series	1,000,000	$ 25.50	**$ 25**	$ 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	$100.00	**200**	200
Total			**$ 929**	$ 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, 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	**$ 27,005**	**$ 544**	**$ (69)**	**$ 27,480**
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	**$ 27,005**	**$ 544**	**$ (69)**	**$ 27,480**
Balance Sheet Items as of December 31, 2006:				
Cash and equivalents	$ 5	$ 78	$ —	$ 83
Accounts receivable – net	893	141	(95)	939
Inventory	218	14	—	232
Other current assets	50	4	—	54
Nonutility property – net of depreciation	727	319	—	1,046
Other long-term assets	481	7	—	488
Total assets	**$ 25,642**	**$ 563**	**$ (95)**	**$ 26,110**
Accounts payable	809	142	(95)	856
Other current liabilities	622	2	—	624
Long-term debt	5,117	54	—	5,171
Asset retirement obligations	2,735	14	—	2,749
Minority interest	—	351	—	351
Total liabilities and shareholders' equity	**$ 25,642**	**$ 563**	**$ (95)**	$ 26,110

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, 2007:				
Operating revenue	$ 10,099	$ 1,129	$ (750)	$ 10,478
Fuel	482	709	—	1,191
Purchased power	3,874	—	(750)	3,124
Provisions for regulatory adjustment clauses – net	271	—	—	271
Other operation and maintenance	2,744	96	—	2,840
Depreciation, decommissioning and amortization	1,058	36	—	1,094
Property and other taxes	217	—	—	217
Total operating expenses	**8,646**	**841**	**(750)**	**8,737**
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**
Income Statement Items for the Year-Ended December 31, 2006:				
Operating revenue	$ 9,926	$ 1,137	$ (751)	$ 10,312
Fuel	389	723	—	1,112
Purchased power	4,160	—	(751)	3,409
Provisions for regulatory adjustment clauses – net	25	—	—	25
Other operation and maintenance	2,575	103	—	2,678
Depreciation, decommissioning and amortization	990	36	—	1,026
Property and other taxes	206	—	—	206
Net gain on sale of utility property and plant	(1)	—	—	(1)
Total operating expenses	**8,344**	**862**	**(751)**	**8,455**
Operating income	**1,582**	**275**	**—**	**1,857**
Interest income	58	—	—	58
Other nonoperating income	85	—	—	85
Interest expense — net of amounts capitalized	(400)	—	—	(400)
Other nonoperating deductions	(60)	—	—	(60)
Income tax expense	(438)	—	—	(438)
Minority interest	—	(275)	—	(275)
Net income	**$ 827**	**—**	**—**	**$ 827**
Income Statement Items for the Year-Ended December 31, 2005:				
Operating revenue	$ 9,038	$ 1,397	$ (935)	$ 9,500
Fuel	269	924	—	1,193
Purchased power	3,557	—	(935)	2,622
Provisions for regulatory adjustment clauses – net	435	—	—	435
Other operation and maintenance	2,421	102	—	2,523
Depreciation, decommissioning and amortization	878	37	—	915
Property and other taxes	193	—	—	193
Net gain on sale of utility property and plant	(10)	—	—	(10)
Total operating expenses	**7,743**	**1,063**	**(935)**	**7,871**
Operating income	**1,295**	**334**	**—**	**1,629**
Interest income	44	—	—	44
Other nonoperating income	127	—	—	127
Interest expense – net of amounts capitalized	(360)	—	—	(360)
Other nonoperating deductions	(65)	—	—	(65)
Income tax expense	(292)	—	—	(292)
Minority interest	—	(334)	—	(334)
Net income	**$ 749**	**—**	**—**	**$ 749**

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

Note 17. Quarterly Financial Data (Unaudited)

	2007				
In millions	Total(1)	Fourth	Third	Second	First
Operating revenue	**$ 10,478**	**$ 2,582**	**$ 3,214**	**$ 2,460**	**$ 2,222**
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**

	2006				
In millions	Total(1)	Fourth	Third	Second	First
Operating revenue	$ 10,312	$ 2,494	$ 3,079	$ 2,521	$ 2,217
Operating income	1,857	315	673	536	332
Net income	827	171	276	247	133
Net income available for common stock	776	158	263	234	121
Common dividends declared	240	60	60	60	60

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

Selected Financial Data: 2003 – 2007 — Southern California Edison Company

Dollars in millions	2007	2006	2005	2004	2003
Income statement data:					
Operating revenue	**$ 10,478**	$ 10,312	$ 9,500	$ 8,448	$ 8,854
Operating expenses	**8,737**	8,455	7,871	6,435	7,276
Purchased-power expenses	**3,124**	3,409	2,622	2,332	2,786
Income tax expense	**337**	438	292	438	388
Provisions for regulatory adjustment clauses – net	**271**	25	435	(201)	1,138
Interest expense – net of amounts capitalized	**429**	400	360	409	457
Net income from continuing operations	**758**	827	749	921	882
Net income	**758**	827	749	921	932
Net income available for common stock	**707**	776	725	915	922
Ratio of earnings to fixed charges	**3.35**	3.97	3.79	4.40	3.80
Balance sheet data:					
Assets	**$ 27,480**	$ 26,110	$ 24,703	$ 23,290	$ 21,771
Gross utility plant	**22,577**	20,734	19,232	17,981	16,991
Accumulated provision for depreciation and decommissioning	**5,174**	4,821	4,763	4,506	4,386
Short-term debt	**500**	—	—	88	200
Common shareholder's equity	**6,228**	5,447	4,930	4,521	4,355
Preferred and preference stock:					
Not subject to mandatory redemption	**929**	929	729	129	129
Subject to mandatory redemption	**—**	—	—	139	141
Long-term debt	**5,081**	5,171	4,669	5,225	4,121
Capital structure:					
Common shareholder's equity	**50.9%**	47.2%	47.7%	45.1%	49.8%
Preferred stock:					
Not subject to mandatory redemption	**7.6%**	8.0%	7.1%	1.3%	1.5%
Subject to mandatory redemption	**—**	—	—	1.4%	1.6%
Long-term debt	**41.5%**	44.8%	45.2%	52.2%	47.1%

The selected financial data was derived form 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.

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5 Nominating/Corporate Governance Committee

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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 24, 2008, at 10:00 a.m., Pacific Time, at the Pacific Palms Conference Resort; One Industry Hills Parkway, City of Industry, California 91744.

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:

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

Fax
(651) 450-4033
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