SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL®* Company

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2005 ANNUAL REPORT

Southern California Edison Company

Southern California Edison Company (SCE) is one of the nation's largest investor-owned electric utilities. Headquartered in Rosemead, California, SCE is a subsidiary of Edison International.

SCE, a 120-year-old electric utility, serves a 50,000-square-mile area of central, coastal and southern California.

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INTRODUCTION

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements reflect Southern California Edison Company's (SCE) 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 California Public Utilities Commission (CPUC) 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 and rates of inflation;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and environmental regulations 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 and output;
- the 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 cost and availability of coal, natural gas, and fuel oil, nuclear fuel, and associated transportation;
- the ability to provide sufficient collateral in support of hedging activities and purchased power and fuel;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- changes in the fair value of investments and other assets accounted for using fair value accounting.

Additional information about risks and uncertainties, including more detail about the factors described above, are discussed throughout this MD&A and the "Risk Factors" section included in Part I, Item IA of SCE's annual report on Form 10-K. Readers are urged to read this entire annual 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 and Exchange Commission.

The MD&A is presented in 11 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) Dispositions and Discontinued Operations; (8) Acquisition; (9) Critical Accounting Estimates; (10) New Accounting Principles; and (11) Commitments and Indemnities.

MANAGEMENT OVERVIEW

In 2005, SCE's focus was on effective execution of Edison International's strategic plan. That plan, announced in October of 2004, set forth a balanced approach for growth, dividends and balance sheet strength. In 2005, SCE met and in some cases exceeded what was set out in the strategic plan as it related to SCE. Principal objectives achieved in 2005 are summarized below:

- Managed growth – In 2005, SCE met all transmission and distribution investment targets, as well as key milestones on future transmission projects. In addition, SCE continued to focus on ensuring adequate generation resources to support customer demand and completed construction of its 1,054 megawatt (MW) Mountainview project and obtained a CPUC decision authorizing the San Onofre Nuclear Generating Station (San Onofre) steam generator replacement project.

- Balance sheet strength – In 2005, SCE took steps to rebalance its capital structure. Liquidity was also enhanced through strong cash flow generation. In addition, credit ratings improved and credit facilities to support hedging and liquidity needs were expanded.

SCE also took significant steps to strengthen the ethics and compliance programs, building a high-priority program to uphold its commitment to integrity and compliance with all regulatory requirements.

In 2006, SCE's primary focus includes:

- Implementation of SCE's capital investment plan to ensure system reliability. SCE plans to undertake new projects to expand its transmission and distribution systems, increase maintenance activities on its electric grid, and begin implementation of a comprehensive, integrated software system to support the majority of its critical business processes. The proposed decision in SCE's 2006 General Rate Case (GRC) would authorize $4.9 billion of capital expenditures for 2006 – 2008, including $2.2 billion in 2006. See "Liquidity—Capital Expenditures" for further discussion of SCE's capital expenditures.

- Progression toward a set of market rules that permit SCE to procure power efficiently ensuring adequate resources are available and creating a downward pressure on customer rates. Beginning in 2006, SCE was required to procure sufficient resources to meet its expected customer needs with a 15–17% reserve margin. SCE expects to meet this resource adequacy requirement in 2006, but access to long-term power resources is needed. In order to provide reliable service SCE continues to focus on securing reasonable long-term procurement rules (see "Regulatory Matters—Current Regulatory Developments"), finding a path to continue to operate the Mohave Generating Station (Mohave) in 2006 on acceptable financial and commercial terms (see "Regulatory Matters—Current Regulatory Developments—Mohave Generating Station and Related Proceedings"), and achieving the milestones for the San Onofre steam generator replacement (see "Regulatory Matters—Current Regulatory Developments—San Onofre Nuclear Generating Station Steam Generators").

- Continuing to be effective in advocating sound, stable and consistent regulatory decisions, including SCE's 2006 GRC application. A proposed decision on SCE's 2006 GRC application was received on January 17, 2006. The proposed decision would result in a 2006 base rate revenue requirement of $3.70 billion, an increase of $61 million over SCE's 2005 base rate revenue. See "Regulatory Matters—Current Regulatory Developments" for further discussion of regulatory matters.

In addition, SCE will continue to enhance the effectiveness of SCE's ethics and compliance programs and will advance company-wide leadership and talent development programs to support its strategic plan objectives.

LIQUIDITY

Overview

As of December 31, 2005, SCE had cash and equivalents of $143 million ($120 million of which was held by SCE's consolidated Variable Interest Entities (VIEs)). As of December 31, 2005, long-term debt, including current maturities of long-term debt, was $5.3 billion. In December 2005, SCE replaced its $1.25 billion credit facility with a $1.7 billion senior secured 5-year revolving credit facility. The security pledged (first and refunding mortgage bonds) for the new facility can be removed at SCE's discretion. If SCE chooses to remove the security, the credit facility's rating and pricing will change to an unsecured basis per the terms of the credit facility agreement. As of December 31, 2005, SCE's credit facility supported $180 million in letters of credit, leaving $1.52 billion available under the credit facility.

SCE's 2006 estimated cash outflows consist of:

- Debt maturities of approximately $596 million, including approximately $246 million of rate reduction notes that have a separate nonbypassable recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures of $2.2 billion primarily to replace and expand distribution and transmission infrastructure and construct and replace generation assets, as discussed below;
- Dividend payments to SCE's parent company. On March 1, 2006, the Board of Directors of SCE declared a $60 million dividend to be paid to Edison International;
- 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 power-procurement undercollections (if incurred), through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary. Projected capital expenditures are expected to be financed through operating cash flows and the issuance of long-term debt and preferred equity.

In January 2006, SCE issued two million shares of 6.0% Series C preference stock (non-cumulative, $100 liquidation value) and received net proceeds of $197 million. In addition, SCE issued $500 million of first and refunding mortgage bonds. The issuance included $350 million of 5.625% bonds due in 2036 and $150 million of variable rate bonds due in 2009. The proceeds from the January 2006 issuances of preference stock and bonds will be used for general corporate purposes, including capital expenditures and debt maturities.

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

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. In April 2005, the Finance Committee of SCE's Board of Directors approved a $10.1 billion capital budget and forecast for the period 2005–2009. Pursuant to the approved capital budget and forecast, SCE expects its capital expenditures to be $2.2 billion in 2006 and $2.1 billion in both 2007 and 2008, including projected environmental capital expenditures of $482 million, $485 million and $500 million in 2006, 2007 and 2006, respectively (see "Other Developments—Environmental Matters"). Significant investments in 2006 are expected to include:

- $1.5 billion related to transmission and distribution projects;
- $300 million related to generation projects;
- $200 million related to information technology projects, including the implementation of a comprehensive integrated software system to support a majority of SCE's critical business processes; and
- $200 million related to other customer service and shared services projects.

Credit Ratings

At December 31, 2005, SCE's credit and long-term senior secured issuer ratings from Standard & Poor's and Moody's Investors Service were BBB+ and A3, respectively. At December 31, 2005, SCE's short-term (commercial paper) credit ratings from Standard & Poor's and Moody's Investors Service were A-2 and P-2, respectively.

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, 2005, SCE's 13-month weighted-average common equity component of total capitalization was 50%. At December 31, 2005, SCE had the capacity to pay $197 million in additional dividends based on the 13-month weighted-average method. Based on recorded December 31, 2005 balances, SCE's common equity to total capitalization ratio, for rate-making purposes, was 50.2%. SCE had the capacity to pay $212 million of additional dividends to Edison International based on December 31, 2005 recorded balances.

SCE has a debt covenant that requires a debt to total capitalization ratio of less than or equal to 0.65 to 1 to be met. At December 31, 2005, SCE's debt to total capitalization ratio was 0.46 to 1.

Margin and Collateral Deposits

In connection with entering into power-purchase agreements to support SCE's procurement plan approved by the CPUC and enter into transactions for imbalance energy with the California Independent System Operator (ISO), SCE has entered into margining agreements for power and gas trading activities to support its risk of nonperformance. SCE's margin deposit requirements can vary depending upon the level of unsecured credit extended by counterparties and brokers, the ISO credit requirements, changes in market prices relative to contractual commitments, and other factors. At December 31, 2005, SCE had a net deposit of $6 million ($158 million recorded in "Margin and collateral deposits" on the balance sheet and $152 million in unrealized gains recorded in "Counterparty collateral" on the balance sheet) with a broker in support of gas trading activities. In addition SCE deposited $200 million (comprised of $20 million in cash and $180 million in letters of credit) with counterparties. Cash deposits with counterparties and brokers earn interest at various rates.

Margin and collateral deposits in support of power purchase agreements and gas trading activities fluctuate with changes in market prices. As of February 28, 2006, SCE had a net deposit of $242 million ($109 million recorded in "Margin and collateral deposits" on the balance sheet and $133 million in unrealized losses recorded in "Counterparty collateral" on the balance sheet) with a broker. In addition, SCE has posted $199 million (comprised of $20 million in cash and $179 million in letters of credit) with counterparties. Future margin and collateral requirements may be higher or lower than the margin collateral requirements as of December 31, 2005 and February 28, 2006, based on future market prices and volumes of trading activity.

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 would 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. SCE opposes any attempt to assign the CDWR contracts. 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.

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 is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE. 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, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE and the transition property is legally not an asset of SCE.

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 Federal Energy Regulatory Commission (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 plant (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 by multiplying an authorized rate of return, determined in annual cost of capital proceedings (as discussed below), by rate base, then adding to this amount the adopted operation and maintenance costs and capital-related carrying costs. 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—2006 General Rate Case Proceeding" for SCE's current annual revenue requirement. 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, while 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 when the application is filed, and 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 2005, 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 6.96%, its authorized cost of preferred equity was 6.73% and its authorized return on common equity was 11.40%. 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. See "—Current Regulatory Developments—2006 Cost of Capital Proceeding" for discussion of SCE's 2006 cost of capital proceeding.

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of reliability and employee safety.

Cost-Recovery Rates

Revenue requirements to recover SCE's costs of fuel, purchased power, demand-side management programs, nuclear decommissioning, rate reduction debt requirements, and public purpose programs are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 52% 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.

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, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (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 $1.9 billion was collected in 2005) 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. At January 1, 2005, SCE's system average rate for bundled customers was 12.2¢-per-kilowatt-hour. As of December 31, 2005, the system average rate was 12.6¢-per-kilowatt-hour. On January 1, 2006, SCE implemented a rate change that resulted in a system average rate of 13.7¢-per-kilowatt-hour. Of the 1.1¢ rate increase, 1¢ was due to the implementation of the CDWR's 2006 revenue requirement approved by the CPUC on December 1, 2005.

SCE implemented a rate change on February 4, 2006. As a result, SCE's current system average rate is 14.3¢-per-kilowatt-hour. The rate increase was due to a 1.2¢ increase resulting from the implementation of SCE's 2006 Energy Resource Recovery Account (ERRA) forecast discussed below, partially offset by a decrease of 0.7¢ due to spreading of the revenue requirement over a larger customer base resulting from forecast sales growth. In addition, the rate change includes authorized increases in funding for demand-side management programs.

Current Regulatory Developments

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

2006 General Rate Case Proceeding

SCE's 2006 GRC application requested a revised 2006 base rate revenue requirement of $3.96 billion, an increase of $325 million over SCE's 2005 base rate revenue. The requested increase is primarily driven by capital expenditures needed to accommodate infrastructure replacement and customer and load growth, and by higher operating and maintenance expenses, particularly in SCE's transmission and distribution business unit. SCE also requested the CPUC continue SCE's existing post-test year rate-making mechanism, which would result in further revised base rate revenue increases of $108 million in 2007 and $113 million in 2008.

On January 17, 2006, the assigned administrative law judge issued his proposed decision, which would result in a 2006 base rate revenue requirement of $3.70 billion, an increase of $61 million over SCE's 2005 base rate revenue. The proposed draft decision contained an error understating the revised 2006 increase. When corrected, the 2006 revenue requirement increase would be $85 million. The proposed decision would reject approximately $121 million of O&M expenses and $143 million of the capital-related revenue requirement that SCE requested. The proposed decision would also reject SCE's post-test year rate-making method and instead escalate 2006 gross additions to 2007 and 2008. The proposed decision's changes would result in base rate revenue increases of $68 million in 2007 and $105 million in 2008. A final CPUC decision is expected by the end of April 2006. SCE cannot predict with certainty the final outcome of SCE's GRC application.

On January 12, 2006, the CPUC approved SCE's request for a GRC memorandum account, which makes the revenue requirement ultimately adopted by the CPUC effective as of that date.

2006 Cost of Capital Proceeding

On December 15, 2005, the CPUC granted SCE's requested rate-making capital structure of 43% long-term debt, 9% preferred equity and 48% common equity for 2006. The CPUC also authorized SCE's 2006 cost of long-term debt of 6.17%, cost of preferred equity of 6.09% and a return on common equity of 11.60%. The CPUC decision resulted in a $23 million decrease in SCE's annual revenue requirement due to lower interest costs partially offset by an increase in return on common equity.

2006 FERC Rate Case

SCE's electric transmission revenue and wholesale and retail transmission rates are subject to authorization by the FERC. On November 10, 2005, SCE filed proposed revisions to the 2006 base transmission rates, which would increase SCE's revenue requirement by $65 million, or 23%, over current base transmission rates, effective on January 10, 2006. On January 9, 2006, FERC accepted the filing, but delayed the rate changes to become effective June 10, 2006, subject to refund. On February 8, 2006, SCE filed a petition for rehearing of the order seeking, among other things, reversal of the FERC's effective date. SCE is unable to predict the revenue requirement that the FERC will ultimately authorize and when the rate changes will become effective.

Energy Resource Recovery Account Proceedings

In 2002, the CPUC established the ERRA as the balancing account mechanism to track and recover SCE's: (1) fuel costs related to its generating stations; (2) purchased-power costs related to cogeneration and renewable contracts; (3) purchased-power costs related to existing interutility and bilateral contracts that were entered into before January 17, 2001; and (4) procurement-related costs incurred on or after January 1, 2003 (the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers). As described above, SCE recovers these costs on a cost-recovery basis, with no markup for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. If the forecast is approved, as these costs are subsequently incurred they are tracked and recovered in customer rates through the ERRA, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA overcollection or undercollection exceeds 5% of SCE's prior year's generation revenue, the CPUC has established a "trigger" mechanism, whereby SCE can request an emergency rate adjustment. As of December 31, 2005, the ERRA was undercollected by $42 million, which was 1.28% of SCE's prior year's generation revenue.

ERRA Forecast

On January 26, 2006, the CPUC approved SCE's 2006 ERRA forecast application, in which it forecasted a power procurement-related revenue requirement for the 2006 calendar year of $4.3 billion, an increase of $961 million over SCE's approved 2005 power procurement-related revenue requirement. The increase was mainly attributable to the substantial increase in natural gas and power prices, load growth and resource adequacy requirements (see the discussion under "—Resource Adequacy Requirements"), the unavailability of Mohave after December 31, 2005, and its replacement with higher-cost natural gas generation (see "—Mohave Generating Station and Related Proceedings"). The increase was implemented in customer rates beginning February 4, 2006.

ERRA Reasonableness Review

From September 1, 2001 through December 31, 2004, the CPUC found all costs recorded in SCE's ERRA account reasonable and prudent, except for minor amounts in 2001.

In addition, from September 1, 2001 through June 30, 2003, the CPUC authorized recovery of amounts paid to Peabody Coal Company for costs associated with the Mohave mine closing, as well as transmission costs related to serving municipal utilities, and also resolved outstanding issues from 2000 and 2001 related to CDWR costs. As a result of this decision, SCE recorded a benefit of $118 million in 2004.

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 with a 15–17% reserve level. Effective February 16, 2006, SCE was required to demonstrate that it had procured sufficient resources to meet 90% of its June–September 2006 resource adequacy requirement. SCE believes that it has met this requirement. Effective in May 2006, SCE will be required to demonstrate that it has met 100% of its resource adequacy requirement one month in advance of expected need. A month-ahead showing demonstrating that SCE has procured 100% of its resource adequacy requirement will be required every month thereafter. The resource adequacy framework provides for penalties of 150% of the cost of new monthly capacity for failing to meet the resource adequacy requirements in 2006, and a 300% penalty in 2007 and beyond. SCE believes it has procured sufficient resources to meet its expected resource adequacy requirements for 2006. In December 2005, the CPUC opened a new resource adequacy rulemaking to address resource adequacy implementation issues, the implementation of local resource adequacy requirements, and other issues related to resource adequacy. A decision on local resource adequacy requirements is expected in June 2006.

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, 2017. The Joint Energy Action Plan adopted in 2003 by the CPUC and the California Energy Commission (CEC) accelerated the deadline to 2010.

SCE entered into a contract with Calpine Energy Services, L.P. (Calpine) to purchase the output of certain existing geothermal facilities in northern California. On January 30, 2003, the CPUC issued a resolution approving the contract. SCE interpreted the resolution as authorizing SCE to count all of the output of the geothermal facilities towards the obligation to increase SCE's procurement from renewable resources and counted the entire output of the facilities toward its 1% obligation in 2003, 2004 and 2005. On July 21, 2005, the CPUC issued a decision stating that SCE can only count procurement pursuant to the Calpine contract towards its 1% annual renewable procurement requirement if it is certified as "incremental" by the CEC. On February 1, 2006, the CEC certified approximately 25% and 17% of SCE's 2003 and 2004 procurement, respectively, from the Calpine geothermal facilities as "incremental." A similar outcome is anticipated with respect to the CEC's certification review for 2005.

On August 26, 2005, SCE filed an application for rehearing and a petition for modification of the CPUC's July 21, 2005 decision. On January 26, 2006, the CPUC denied SCE's application for rehearing of the decision. The CPUC has not yet ruled on SCE's petition for modification. The petition for modification seeks a clarification that SCE will not be subjected to penalties for relying on the CPUC's 2003 resolution in submitting compliance reports to the CPUC and planning its subsequent renewable procurement activities. The petition for modification also seeks an express finding that the decision will be applied prospectively only; *i.e.*, that no past procurement deficits will accrue for any prior period based on the decision.

If SCE is not successful in its attempt to modify the July 21, 2005 CPUC decision and can only count the output deemed "incremental" by the CEC, SCE could have deficits in meeting its renewable procurement obligations for 2003 and 2004. However, based on the CPUC's rules for compliance with renewable procurement targets, SCE believes that it will have until 2007 to make up these deficits before becoming subject to penalties for those years. The CEC's and the CPUC's treatment of the output from the geothermal facilities could also result in SCE being deemed to be out of compliance in 2005 and 2006. Under current CPUC decisions, potential penalties for SCE's failure to achieve its renewable procurement obligations for any year will be considered by the CPUC in SCE's annual compliance filing.

On December 20, 2005, Calpine and certain of its affiliates initiated Chapter 11 bankruptcy proceedings in the United States Bankruptcy Court for the Southern District of New York. As part of those proceedings, Calpine sought to reject its contract with SCE as of the petition filing date. On January 27, 2006, after the matter had been withdrawn from the Bankruptcy Court's jurisdiction, the United States District Court for the Southern District of New York denied Calpine's motion to reject the contract and ruled that the FERC has exclusive jurisdiction to alter the terms of the contract with SCE. Calpine has appealed the District Court's ruling to the United States Court of Appeals for the Second Circuit. Calpine may also file a petition with the FERC seeking authorization to reject the contract. The CPUC may take the position that any authorized rejection of the contract would cause SCE to be out of compliance with its renewable procurement obligations during any period in which renewable electricity deliveries are reduced or eliminated as a result of the rejection.

Further, in December 2005, SCE made filings advising the CPUC that the need for transmission upgrades to interconnect new renewable projects and the time it will take under the current process to license and construct such transmission upgrades may prevent SCE from meeting its statutory renewables procurement obligations through 2010 and potentially beyond 2010 depending in part on the results of a pending solicitation for new renewable resources. SCE has requested that the CPUC take several actions in order to expedite the licensing process for transmission upgrades. The CPUC may take the position that SCE's failure to meet the 20% goal by 2010 due to transmission constraints would cause SCE to be out of compliance with its renewable procurement obligations.

Under the CPUC's current rules, the maximum penalty for failing to achieve renewables procurement targets is $25 million per year. SCE cannot predict with certainty 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 Navajo Nation and Hopi Tribe (the Tribes). This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which requires water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over a 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 that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

Negotiations, water studies, and other efforts have continued among the relevant parties in an attempt to resolve Mohave's post-2005 coal and water supply issues. Although progress has been made with respect to certain issues, no complete resolution has been reached to date, and efforts to resolve these issues continue. The plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the 1999 consent decree. SCE remains committed to the environmental objectives underlying that decree. SCE is also committed to pursuing all reasonable options to return Mohave to service pursuant to the existing consent decree provisions or, if interim operation is permitted pending installation of controls, pursuant to additional legal provisions which provide appropriate protection of the environment. However, at this time, SCE does not know the length of the shutdown period, and a permanent shutdown remains possible. The outcome of the efforts to resolve the post-2005 coal and water supply issues did not impact Mohave's operation through 2005, but the presence or absence of Mohave as an available resource beyond 2005 will impact SCE's long-term resource plan. SCE's 2006 ERRA forecast application assumes Mohave is an unavailable resource for power for 2006 (see "—Energy Resource Recovery Account Proceedings—ERRA Forecast" for further discussion). SCE expects to recover Mohave shut-down costs in customer rates.

In light of the issues discussed above, in 2002 SCE concluded that it was probable Mohave would be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million in 2002. However, in accordance with accounting standards for rate-regulated enterprises, this incurred charge was deferred and recorded in regulatory assets as a long-term receivable based on SCE's expectation that the unrecovered book value at the end of 2005 would be recovered in future rates (together with a reasonable return) through a balancing account mechanism. Subsequent charges related to capital additions were also deferred and recorded in regulatory assets. As of December 31, 2005 the regulatory balance related to the Mohave impairment was $81 million.

For additional matters related to Mohave, see "Other Developments—Navajo Nation Litigation."

San Onofre Nuclear Generating Station Steam Generators

On December 15, 2005, the CPUC issued a final decision on SCE's application for replacement of SCE's San Onofre Units 2 and 3 steam generators. In that decision, the CPUC found that: (1) steam generator replacement is cost-effective; (2) SCE's estimate of the total cost of steam generator replacement of $680 million ($569 million for replacement steam generator installation and $111 million for removal and disposal of the original steam generators) is reasonable; (3) SCE will be able to recover all of its incurred costs and the CPUC does not intend to conduct an after-the-fact reasonableness review if the project is completed at a cost that does not exceed $680 million as adjusted for inflation and allowance for funds used during construction; (4) a reasonableness review will be required if the project is completed at a cost between $680 million and $782 million or the CPUC later finds that it had reason to believe the costs may be unreasonable regardless of the amount; (5) if the cost of the project exceeds $782 million, no rate recovery will be allowed for costs above $782 million as adjusted for inflation and allowance for funds used during construction; (6) traditional cost-of-service ratemaking should govern recovery of future operating and maintenance and capital expenditures for plant operation; (7) SCE's actions in relation to the issue of potential claims against the manufacturer of the steam generators or its successors were reasonable; and (8) SDG&E must file an application with the CPUC concerning the transfer of its ownership share of San Onofre Units 2 and 3 to SCE by April 14, 2006. SCE must provide written notice of its acceptance of the conditions set forth in the decision within 85 days. On January 18, 2006, the Utility Reform Network and California Earth Corps filed an application for rehearing challenging, among other things, the cost benefit analysis, rejection of future spending caps, the timing for initiation of the analysis, and the portion of the final decision finding that SCE acted reasonably in pursuing claims against the manufacturer of the steam generators.

SCE's share of the total estimated cost of the steam generator replacement project based on its current ownership percentage of 75.05% is $510 million. SCE and the city of Anaheim have agreed to an early transfer of Anaheim's 3.16% share of San Onofre, which would increase SCE's share of the total estimated costs to $532 million. By April 14, 2006, SDG&E is expected to apply to the CPUC to transfer all or a portion of its 20% share of San Onofre to SCE. If SDG&E's entire 20% share is transferred to SCE, it would increase SCE's share of the total estimated costs to $668 million. Any transfer of SDG&E's ownership in San Onofre would require the approval of the CPUC and the FERC. Any transfer of Anaheim's share in San Onofre would require CPUC approval of ratemaking for SCE's acquired share and approval by the FERC.

Palo Verde Steam Generating Station Steam Generators

SCE owns a 15.8% interest in the Palo Verde Nuclear Generating Station (Palo Verde). During 2003, the Palo Verde Unit 2 steam generators were replaced. During 2005, the Palo Verde Unit 1 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture and installation of steam generators in Unit 3. SCE expects that replacement steam generators will be installed in Unit 3 in 2008. SCE's share of the costs of manufacturing and installing all the replacement steam generators at Palo Verde is estimated to be approximately $115 million. The CPUC approved the replacement costs for Unit 2 in the 2003 GRC. The proposed decision in the 2006 GRC proceeding would allow SCE to recover the replacement costs for Units 1 and 3.

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 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 (SCs) in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from SCs 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 California Power Exchange (PX), SCE's SC 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 February 7, 2006, the FERC advised SCE that the FERC will move the Court of Appeals for a voluntary remand so that the FERC may amend the order on appeal. A decision is expected in late 2006. The FERC may require SCE to pay these costs, but SCE does not believe this outcome is probable. If SCE is required to pay these costs, SCE may seek recovery in its reliability service rates.

Transmission Proceeding

In August and November 2002, the FERC issued opinions affirming a September 1999 administrative law judge decision to disallow, among other things, recovery by SCE and the other California public utilities of costs reflected in network transmission rates associated with ancillary services and losses incurred by the utilities in administering existing wholesale transmission contracts after implementation of the restructured California electric industry. SCE has incurred approximately $80 million of these unrecovered costs since 1998. In addition, SCE has accrued interest on these unrecovered costs. The three California utilities appealed the decisions to the Court of Appeals for the D.C. Circuit. On July 12, 2005, the Court of Appeals for the D.C. Circuit vacated the FERC's August and November 2002 orders, and remanded the case to the FERC for further proceedings. On December 20, 2005, the FERC authorized SCE and the other California public utilities to recover the costs through their existing FERC tariffs. As a result, SCE recorded a benefit of approximately $93 million (including $23 million related to interest which is reflected in the consolidated statements of income caption "Interest expense – net of amounts capitalized").

FERC Refund Proceedings

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the PX and ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. 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. SCE is required to refund to customers 90% of any refunds actually realized by SCE net of litigation costs, except for the El Paso Natural Gas Company settlement agreement discussed below, and 10% will be retained by SCE as a shareholder incentive. A brief summary of the various settlements is below:

- In June 2004, SCE received its first settlement payment of $76 million resulting from a settlement agreement with El Paso Natural Gas Company. Approximately $66 million of this amount was credited to purchased-power expense, and was refunded to SCE's ratepayers through the ERRA mechanism over the following twelve months, and the remaining $10 million was used to offset SCE's incurred legal costs. In May 2005, SCE received its final settlement payment of $66 million, which was also refunded to ratepayers through the ERRA mechanism.
- In August 2004, SCE received its $37 million share of settlement proceeds resulting from a FERC approved settlement agreement with The Williams Cos. and Williams Power Company.
- In November 2004, SCE received its $42 million share of settlement proceeds resulting from a FERC-approved settlement agreement with West Coast Power, LLC and its owners, Dynegy Inc. and NRG Energy, Inc.
- In January 2005, SCE received its $45 million share of settlement proceeds resulting from a FERC-approved settlement agreement with Duke Energy Corporation and a number of its affiliates.
- In April 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E and several governmental entities, and Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in Chapter 11 bankruptcy proceedings pending in Texas. In April and May 2005, SCE received its $68 million share of the cash portion of the settlement proceeds. SCE also received a $33 million share of an allowed, unsecured claim in the bankruptcy of one of the Mirant parties which was sold for $35 million in December 2005.
- In November 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E and several governmental entities, and Enron Corporation and a number of its affiliates (collectively Enron), most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In January 2006, SCE received cash settlement proceeds of $4 million for legal fees and anticipates receiving approximately $5 million in additional cash proceeds assuming certain contingencies are satisfied. SCE also received an allowed, unsecured claim against one of the Enron debtors in the amount of $241 million. In February 2006, SCE received a partial distribution of $10 million of its allowed claim. The remaining amount of the allowed claim that will actually be realized will depend on events in Enron's bankruptcy that impacts the value of the relevant debtor estate.
- In December 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E, several governmental entities and certain other parties, and Reliant Energy, Inc. and a number of its affiliates (collectively Reliant). In January 2006, SCE received $65 million of the settlement proceeds. SCE expects to receive an additional $66 million in 2006.

During 2005, SCE recognized $23 million in shareholder incentives related to the FERC refunds described above which is reflected in the consolidated statements of income caption "Other nonoperating income."

Holding Company Order Instituting Rulemaking

On October 27, 2005, the CPUC issued an order instituting rulemaking (OIR) to allow the CPUC to re-examine the relationships of the major California energy utilities with their parent holding companies and non-regulated affiliates. The OIR was issued in part in response to the recent repeal of the Public Utility Holding Company Act of 1935.

By means of the OIR, the CPUC will consider whether additional rules to supplement existing rules and requirements governing relationships between the public utilities and their holding companies and non-regulated affiliates should be adopted. Any additional rules will focus on whether (1) the public utilities retain enough capital or access to capital to meet their customers' infrastructure needs and (2) mitigation of potential conflicts between ratepayer interests and the interests of holding companies and affiliates that could undermine the public utilities' ability to meet their public service obligations at the lowest cost.

Demand-Side Management and Energy Efficiency Performance Incentive Mechanisms

Under a variety of incentive mechanisms adopted by the CPUC in the past, SCE was entitled to certain shareholder incentives for its performance achievements in delivering demand-side management and energy efficiency programs. On June 10, 2005, SCE and the CPUC's Division of Ratepayer Advocates executed a settlement agreement for SCE's outstanding issues concerning SCE shareholder incentives and performance achievements resulting from the demand-side management, energy efficiency, and low-income energy efficiency programs from program years 1994–2004. In addition, the settlement addresses shareholder incentives anticipated but not yet claimed for performance achievements in program years 1994–1998. The settling parties agreed that it is reasonable for SCE to recover approximately $42 million of these claims plus interest in the near future as full recovery of all of SCE's outstanding claims as well as future claims related to SCE's pre-1998 energy efficiency programs.

On October 27, 2005, the CPUC approved the settlement agreement. As a result of the decision, SCE recognized a $45 million benefit in 2005 for the claims settled and other related items, reflected in the consolidated statements of income caption "Other nonoperating income."

Investigations Regarding Performance Incentives Rewards

SCE is 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 has been conducting investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below. As a result of the reported events, the CPUC could institute its own proceedings to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, injury and illness reporting, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE. SCE cannot predict with certainty the outcome of these matters or estimate the potential amount of refunds, disallowances, and penalties that may be required.

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 to SCE under the PBR provisions for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 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. As a result of these findings, SCE accrued a $9 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by severing the employment of 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.

The CPUC has not yet opened a formal investigation into this matter. However, it has submitted several data requests to SCE and has requested an opportunity to interview a number of SCE employees in the design organization. SCE has responded to these requests and the CPUC has conducted interviews of approximately 20 employees who were disciplined for misconduct and four senior managers and executives of the transmission and distribution business unit.

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 received $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 for any year before 2005, and it return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001–2003 time frames.

SCE has taken other remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance and disciplining employees who committed wrongdoing. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004. As with the customer satisfaction matter, the CPUC has not yet opened a formal investigation into this matter.

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. On February 28, 2005, SCE provided its final investigatory report to the CPUC concluding that the reliability reporting system is working as intended.

OTHER DEVELOPMENTS

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation 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, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss. The D.C. District Court denied these motions for dismissal, except for Salt River Project Agricultural Improvement and Power District's motion for its separate dismissal from the lawsuit.

Certain issues related to this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the United States Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's conclusion, SCE and Peabody brought motions to dismiss or for summary judgment in the D.C. District Court action but the D.C. District Court denied the motions on April 13, 2004.

The Court of Appeals for the Federal Circuit, acting on a suggestion filed by the Navajo Nation on remand from the Supreme Court's March 4, 2003 decision held, in an October 24, 2003 decision that the Supreme Court's decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. On March 16, 2004, the Federal Circuit issued an order remanding the case against the Government to the Court of Federal Claims, which considered (1) whether the Navajo Nation previously waived its "network of other laws" argument and, (2) if not, whether the Navajo Nation can establish that the Government breached any fiduciary duties pursuant to such "network." On December 20, 2005, the Court of Federal Claims issued its ruling and found that although there was no waiver, the Navajo Nation did not establish that a "network of other laws" created a judicially enforceable trust obligation. The Navajo Nation filed a notice of appeal from this ruling on February 14, 2006.

Pursuant to a joint request of the parties, the D.C. District Court granted a stay of the action in that court to allow the parties to attempt to resolve, through facilitated negotiations, all issues associated with Mohave. Negotiations are ongoing and the stay has been continued until further order of the court.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact on the complaint of the Supreme Court's decision and the recent Court of Federal Claims ruling in the Navajo Nation's suit against the Government, or the impact of the complaint on the possibility of resumed operation of Mohave following the cessation of operation on December 31, 2005.

Environmental Matters

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 existing environmental regulatory requirements.

SCE's power plants, in particular its coal-fired plants, may be affected by recent developments in federal and state laws and regulations. These laws and regulations, including those relating to sulfur dioxide and nitrogen oxide emissions, mercury emissions, ozone and fine particulate matter emissions, regional haze, and climate change, may require SCE to make significant capital expenditures at its facilities. The developments in certain of these laws and regulations are discussed in more detail below. These developments will continue to be monitored by SCE 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.

The enactment of more stringent environmental laws and regulations could affect the costs and the manner in which SCE's 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's projected environmental capital expenditures over the next three years are: 2006 – $482 million; 2007 – $485 million; and 2008 – $500 million. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines.

Air Quality Standards

In 1998, several environmental groups filed suit against the co-owners of the Mohave plant regarding alleged violations of emissions limits. In order to resolve the lawsuit and accelerate resolution of key environmental issues regarding the plant, the parties entered into a consent decree, which was approved by the Nevada federal district court in December 1999. The consent decree required the installation of certain air pollution control equipment prior to December 31, 2005 if the plant was to operate beyond that date. In addition, operation beyond 2005 required that agreements be reached with the Navajo Nation and the Hopi Tribe (Tribes) regarding post-2005 water and coal supply needs.

SCE's share of the costs of complying with the consent decree and taking other actions to allow operation of the Mohave plant beyond 2005 is estimated to be approximately $605 million. Agreement with the Tribes on water and coal supplies for Mohave was not reached by December 31, 2005, and it is not currently known whether such an agreement will be reached. No agreement was reached to amend the terms of the federal court consent decree. As a result, Mohave shutdown operation on December 31, 2005. For the Mohave plant to restart operation, it will be necessary for agreements to be reached with the Navajo Nation and the Hopi Tribe on the water and coal supply issues, and for the terms of the consent decree to be met or modified. See "Regulatory Matters—Current Regulatory Developments—Mohave Generating Station and Related Proceedings" for further discussion of the Mohave issues.

Climate Change

In California, Governor Schwarzenegger issued an executive order on June 1, 2005, setting forth targets for greenhouse gas reductions. The targets call for a reduction of greenhouse gas emissions to 2000 levels by 2010; a reduction of greenhouse gas emissions to 1990 levels by 2020; and a reduction of greenhouse gas emissions to 80% below 1990 levels by 2050. The CPUC is addressing climate change related issues in various regulatory proceedings.

SCE will continue to monitor these developments relating to greenhouse gas emissions to determine their impacts on SCE's operations. Any legal obligation that would require SCE to reduce substantially its emissions of carbon dioxide could require extensive mitigation efforts at its Mohave plant if it resumes operations, and would raise considerable uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generating facilities. New regulations could also increase the cost of purchased power, which is generally borne by SCE's customers. Additional information regarding purchased power costs appears under the heading "Regulatory Matters."

Environmental Remediation

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

SCE's recorded estimated minimum liability to remediate its 24 identified sites is $82 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $115 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 had 31 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $30 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 $56 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 $25 million. Recorded costs for 2005 were $13 million.

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 Income Taxes

Edison International has reached a settlement with the IRS on tax issues and pending affirmative claims relating to its 1991–1993 tax years. This settlement, which was signed by Edison International in March 2005 and approved by the United States Congress Joint Committee on Taxation on July 27, 2005, resulted in a third quarter 2005 net earnings benefit for SCE of approximately $61 million, including interest. This benefit was reflected in the caption "Income tax" on the consolidated statements of income.

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would benefit SCE as future tax deductions.

The IRS Revenue Agent Report for the 1997–1999 audit also 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. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

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 however 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 (11.4% for 2005 and 11.6% for 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, 2005, SCE did not believe that its short-term debt and current portion of long-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value.

At December 31, 2005, the fair market value of SCE's long-term debt was $4.8 billion. A 10% increase in market interest rates would have resulted in a $233 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 $256 million increase in the fair market value of SCE's long-term debt.

Commodity Price Risk

SCE forecasts that it will have a net-long position (generation supply exceeds expected load requirements) in the majority of hours during 2006. SCE's net-long position arises primarily from resource adequacy requirements set by the CPUC 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"). SCE has incorporated a 2005 price and volume forecast from expected sales of net-long power in its 2006 revenue forecast used for setting rates. If actual prices or volumes vary from forecast, SCE's cash flow could be temporarily impacted due to regulatory recovery delays, but such variations are not expected to affect earnings. For 2006, SCE forecasts that at certain times it will have a net-short position (expected load requirements exceed generation supply). SCE's forecast net-short position is expected to increase each year, assuming no new generation supply is added, existing contracts expire, SCE generating plants retire, and load grows. The establishment of a sufficient planning reserve margin mitigates, to some extent, several conditions that could increase SCE's net-short position, including lower utility generation due to expected or unexpected outages or plant closures, lower deliveries under third-party power contracts, or higher than anticipated demand for electricity. However, SCE's planning reserve margin may not be sufficient to supply the needs of all returning direct access customers (customers who choose to purchase power directly from an electric service provider other than SCE but then decide to return to utility service). Increased procurement costs resulting from the return of direct access customers could lead to temporary undercollections and the need to adjust rates.

SCE anticipates purchasing additional capacity and/or ancillary services to meet its peak-energy requirements in 2006 and beyond if its net-short position is significantly higher than SCE's current forecast. As of December 31, 2005, SCE entered into energy options and tolling arrangements and forward physical contracts to mitigate its exposure to energy prices in the spot market. The fair market value of the energy options and tolling arrangements as of December 31, 2005, was a net asset of $25 million. A 10% increase in energy prices would have resulted in a $208 million increase in the fair market value. A 10% decrease in energy prices would have resulted in a $143 million decrease in the fair market value. The fair market value of the forward physical contracts as of December 31, 2005, was a net liability of $49 million. A 10% increase in energy prices would have resulted in a $52 million increase in the fair market value. A 10% decrease in energy prices would have resulted in a $53 million decrease in the fair market value.

SCE is also exposed to increases in natural gas prices related to its qualifying facilities (QF) contracts, fuel tolling arrangements, and owned gas-fired generation, including the Mountainview project. 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 known as fuel tolling arrangements. SCE has an active gas fuel hedging program in place to minimize ratepayer exposure to spot market price spikes. However, movements in gas prices over time will impact SCE's gas costs and the cost of QF power which is related to natural gas prices.

As of December 31, 2005, SCE entered into gas forward transactions including options, swaps and futures, and fixed price contracts to mitigate its exposure related to the QF contracts and fuel tolling arrangements. The fair market value of the forward transactions as of December 31, 2005, was a net asset of $105 million. A 10% increase in gas prices would have resulted in a $105 million increase in the fair market value. A 10% decrease in gas prices would have resulted in a $104 million decrease in the fair market value. SCE cannot predict with certainty whether in the future it will be able to hedge customer risk for other commodities on favorable terms or that the cost of such hedges will be fully recovered in rates.

SCE's purchased-power costs, as well as its gas expenses and gas hedging costs, are recovered through 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.

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.

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

Income from Continuing Operations

SCE's income from continuing operations was $749 million in 2005, compared to $921 million in 2004. SCE's 2005 earnings included positive items of $61 million related to a favorable tax settlement (see "Other Developments—Federal Income Taxes"), $55 million from a favorable FERC decision on a SCE transmission proceeding (see "Regulatory Matters—Current Regulatory Developments—Transmission Proceeding") and a $14 million incentive benefit from generator refunds related to the California energy crisis period (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings"). SCE's 2004 earnings included $329 million of positive regulatory and tax items, primarily from implementation of the 2003 GRC decision that was received in July 2004. Excluding these positive items, earnings were up $27 million due to higher net revenue, including tax benefits, and lower financing costs, partially offset by the impact of a lower CPUC-authorized rate of return in 2005.

SCE's income from continuing operations in 2004 was $921 million, compared to $882 million in 2003. The $39 million increase between 2004 and 2003 was mainly due to the resolution of regulatory proceedings and prior years' tax issues which increased income by $86 million over 2003. The 2004 proceedings included the 2003 GRC that was resolved in July 2004 and the 2003 ERRA proceeding addressing power procurement reasonableness that was resolved in the fourth quarter of 2004. Also, in the fourth quarter of 2004, SCE favorably resolved prior years' tax issues. Excluding these items, income decreased $47 million, primarily from the expiration at year-end 2003 of the ICIP mechanism at San Onofre partially offset by the increase in revenue authorized by the 2003 GRC decision. Post-test-year revenue increases for 2004 and 2005, to compensate for customer growth and increased capital expenditures were authorized in the 2003 GRC decision.

Operating Revenue

SCE's retail sales represented approximately 82%, 85%, and 91% of operating revenue for the years ended December 31, 2005, 2004, and 2003, respectively. Due to warmer weather during the summer months, operating revenue during the third quarter of each year is generally significantly higher than other quarters.

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

In millions Year ended December 31,	**2005 vs. 2004**	2004 vs. 2003
Operating revenue		
Rate changes (including unbilled)	**$ 517**	$ (677)
Sales volume changes (including unbilled)	**410**	(159)
Deferred revenue	**(324)**	(30)
Sales for resale	**256**	164
SCE's variable interest entities	**177**	285
Other (including intercompany transactions)	**16**	11
Total	**$ 1,052**	$ (406)

Total operating revenue increased by $1.1 billion in 2005 (as shown in the table above). The variance in operating revenue from rate changes reflects the implementation of the 2003 GRC, effective in August 2004. As a result, generation and distribution rates increased revenue by approximately $166 million and $351 million, respectively. The increase in operating revenue resulting from sales volume changes was mainly due to an increase in kilowatt-hour (kWh) sold and SCE providing a greater amount of energy to its customers from its own sources in 2005, compared to 2004. The change in deferred revenue reflects the deferral of approximately $93 million of revenue in 2005, resulting from balancing account overcollections, compared to the recognition of approximately $231 million in 2004. Operating revenue from sales for resale represents the sale of excess energy. As a result of the CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times, which then is resold in the energy markets. Revenue from sales for resale is refunded to customers through the ERRA rate-making mechanism and does not impact earnings. SCE's variable interest entities revenue represents the recognition of revenue resulting from the consolidation of SCE's variable interest entities on March 31, 2004.

Total operating revenue decreased by $406 million in 2004 (as shown in the table above). The reduction in operating revenue due to rate changes resulted from the implementation of a CPUC-approved customer rate reduction plan effective August 1, 2003, additional rate changes effective in 2004 resulting from implementation of the 2003 GRC (an increase in distribution rates and a further decrease in generation rates), and an allocation adjustment for the CDWR energy purchases recorded in 2003. The decrease in electric revenue resulting from sales volume changes was mainly due to the CDWR providing a greater amount of energy to SCE's customers in 2004, as compared to 2003, partially offset by an increase in kWh sold. Sales for resale increased due to a greater amount of excess energy in 2004, as compared to 2003. As a result of the CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times, which then is resold in the energy markets. SCE's variable interest entities revenue represents the recognition of revenue resulting from the consolidation of SCE's variable interest entities beginning March 31, 2004.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001), CDWR bond-related costs (beginning November 15, 2002) and a portion of direct access exit fees (beginning January 1, 2003) are remitted to the CDWR and are not recognized as revenue by SCE. These amounts were $1.9 billion, $2.5 billion, and $1.7 billion for the years ended December 31, 2005, 2004, and 2003, respectively.

Operating Expenses

Fuel Expense

SCE's fuel expense increased $383 million in 2005 and $575 million in 2004 primarily due to the consolidation of SCE's variable interest entities on March 31, 2004 resulting in the recognition of fuel expense of $924 million in 2005 and $578 million in 2004.

Purchased-Power Expense

Purchased-power expense increased $290 million in 2005 and decreased $454 million in 2004. The 2005 increase was mainly due to higher firm energy and QF-related purchases, partially offset by net realized and unrealized gains on economic hedging transactions and an increase in energy settlement refunds in 2005, as compared to 2004. Firm energy purchases increased by approximately $670 million resulting from an increase in the number of bilateral contracts in 2005, as compared to 2004, and QF-related purchases increased by approximately $170 million in 2005, as compared to 2004 (as discussed below). Net realized and unrealized gains related to economic hedging transactions reduced purchased-power expense by approximately $205 million in 2005, as compared to net realized and unrealized losses of approximately $25 million which increased purchased-power expense in 2004. Energy settlement refunds received in 2005 and 2004 were approximately $285 million and $190 million, respectively, further decreasing purchased-power expense in these periods (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings"). The consolidation of SCE's variable interest entities effective March 31, 2004 resulted in a $935 million and $669 million reduction in purchased-power expense in 2005 and 2004, respectively. The 2004 decrease was mainly due to the consolidation of SCE's variable interest entities and energy settlement refunds received (both discussed above), partially offset by higher expenses of approximately $150 million related to power purchased by SCE from QFs (as discussed below), higher expenses of approximately $100 million resulting from an increase in the number of gas bilateral contracts in 2004, as compared to 2003, and higher expenses of approximately $130 million related to ISO purchases.

Also included in purchased-power expense in 2005 is a $25 million charge related to amounts billed to the Los Angeles Department of Water & Power (DWP) for scheduling coordinator charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges are billed to DWP under a FERC tariff that remains subject to dispute. DWP has paid the amounts billed under protest but requested 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 DWP have not been shown to be just and reasonable and thus made them subject to refund and further review at the FERC. As a result, SCE could be required to refund all or part of the amounts collected from DWP under the tariff. If the FERC ultimately rules that SCE may not collect the scheduling coordinator charges from DWP and requires the amounts collected to be refunded to DWP, SCE would attempt to recover the scheduling coordinator charges from all transmission grid customers through another regulatory mechanism. However, the availability of other recovery mechanisms is uncertain, and ultimate recovery of the scheduling coordinator charges cannot be assured.

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. Effective May 2002, energy payments for most renewable QFs were converted to a fixed price of 5.37¢-per-kWh. Average spot natural gas prices were higher during 2005 as compared to 2004. The higher expenses related to power purchased from QFs were mainly due to higher average spot natural gas prices, partially offset by lower kWh purchases.

Provisions for Regulatory Adjustment Clauses – Net

Provisions for regulatory adjustment clauses – net increased $636 million in 2005 and decreased $1.3 billion in 2004. The 2005 increases mainly result from regulatory adjustments recorded in 2004, net overcollections related to balancing accounts, higher net unrealized gains on economic hedging transactions and lower CEMA-related costs. The net regulatory adjustments of $345 million recorded in 2004 related to the implementation of SCE's 2003 GRC decision and the implementation of an ERRA-related CPUC decision (see "Regulatory Matters—Current Regulatory Developments—Energy Resource Recovery Account Proceedings"). In addition to these net regulatory adjustments, the increase reflects higher net overcollections of purchased power, fuel, and operating and maintenance expenses of approximately $65 million which were deferred in balancing accounts for future recovery, higher net unrealized gains of approximately $95 million related to economic hedging transactions (mentioned above in purchased-power expense) that, if realized, would be refunded to ratepayers, and lower costs incurred and deferred of approximately $95 million associated with CEMA-related costs (primarily bark beetle infestation related costs). The 2003 GRC regulatory adjustments primarily related to recognition of revenue from the rate recovery of pension contributions during the time period that the pension plan was fully funded, resolution over the allocation of costs between transmission and distribution for 1998 through 2000, partially offset by the deferral of revenue previously collected during the incremental cost incentive pricing mechanism for dry cask storage, as well as pre-tax gains related to the 1997–1998 generation-related capital additions. The

2004 decrease was mainly due to the collection of the Procurement-Related Obligations Account (PROACT) balance in 2003 and the implementation of the CPUC-authorized rate-reduction plan in the summer of 2003, resulting in decreases of approximately $700 million. The decrease also reflects a net effect of regulatory adjustments discussed above and the deferral of costs for future recovery in the amount of approximately $100 million associated with the bark beetle infestation. The 2004 decrease was partially offset by approximately $190 million in settlement agreement payments received and refunded to ratepayers and shareholder incentives (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings"), the favorable resolution of certain regulatory cases recorded in the third quarter of 2003, and an allocation adjustment of approximately $110 million for CDWR energy purchases recorded in 2003.

Other Operation and Maintenance Expense

SCE's other operating and maintenance expense increased $66 million in 2005 and $385 million in 2004. The 2005 increase was mainly due to an increase in reliability costs, demand-side management and energy efficiency costs, and benefit-related costs, partially offset by lower CEMA-related costs and generation-related costs. Reliability costs increased approximately $80 million, as compared to 2004, due to an increase in must-run units to improve the reliability of the California ISO systems operations (which are recovered through regulatory mechanisms approved by the FERC). Demand-side management and energy efficiency costs increased approximately $90 million (which are recovered through regulatory mechanisms approved by the CPUC). Benefit-related costs increased approximately $50 million in 2005, resulting from an increase in heath care costs and value of performance shares. The 2005 increase was partially offset by lower CEMA-related costs (primarily bark beetle infestation related costs) of approximately $95 million and a decrease in generation-related expenses of approximately $90 million, resulting from lower outage and refueling costs (in 2004, there was a scheduled major overhaul at SCE's Four Corners coal facility, as well as a refueling outage at SCE's San Onofre Unit 2). The 2005 variance also reflects an increase of approximately $35 million resulting from the consolidation of SCE's variable interest entities effective March 31, 2004. The 2004 increase was mainly due to approximately $130 million of costs incurred in 2004 related to the removal of trees and vegetation associated with the bark beetle infestation, higher operation and maintenance costs of approximately $60 million related to the San Onofre refueling outages in 2004, operating and maintenance expense of $66 million related to the consolidation of SCE's variable interest entities, higher operation and maintenance costs related to a scheduled major overhaul at SCE's Four Corners coal facility and additional costs for 2003 incentive compensation due to upward revisions in the computation in 2004. These increases were partially offset by a decrease in postretirement benefits other than pensions expense, including the effects of adopting the Medicare Prescription Drug, Improvement and Modernization Act of 2003 in the third quarter of 2004 and lower worker's compensation claims in 2004.

Depreciation, Decommissioning and Amortization Expense

SCE's depreciation, decommissioning and amortization increased $55 million in 2005 and decreased $22 million in 2004. The increase in 2005 is mainly due to a change in the Palo Verde rate-making mechanisms resulting from the implementation of the 2003 GRC and an increase in depreciation expense resulting from additions to transmission and distribution assets. The 2004 decrease was mainly due to a change in the Palo Verde and San Onofre rate-making mechanisms in 2003 and 2004, partially offset by an increase in SCE's depreciation associated with additions to transmission and distribution assets, the consolidation of SCE's variable interest entities, and an increase in nuclear decommissioning expense.

Other Income and Deductions

Interest and Dividend Income

SCE's interest and dividend income increased $24 million in 2005 and decreased $80 million in 2004. The undercollections in 2005 as compared to 2004. The 2004 decrease was mainly due to the absence of interest income on the PROACT balance. At July 31, 2003, the PROACT balance was overcollected and was transferred to the ERRA on August 1, 2003.

Other Nonoperating Income

SCE's other nonoperating income increased $43 million in 2005 mainly due to the recognition of approximately $45 million in incentives related to demand-side management and energy efficiency performance (see "Regulatory Matters—Current Regulatory Developments—Demand-Side Management and Energy Efficiency Performance Incentive Mechanisms" for further discussion of this matter) and an increase in shareholder incentives related to the FERC settlement refunds. SCE recorded shareholder incentives of $23 million in 2005 and $12 million in 2004 (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings" for further discussion). In addition, other nonoperating income includes rewards approved by the CPUC for the efficient operation of Palo Verde of $10 million in 2005 and $19 million in 2004.

Interest Expense – Net of Amounts Capitalized

SCE's interest expense – net of amounts capitalized decreased $49 million in 2005 and $48 million in 2004. Effective July 1, 2003, dividend payments on preferred securities subject to mandatory redemption are included as interest expense based on the adoption of a new accounting standard. The new standard did not allow for prior period restatements, therefore dividends on preferred securities subject to mandatory redemption for the first six months of 2003 are not included in interest expense – net of amounts capitalized in the consolidated statements of income. In addition, the 2005 and 2004 decreases were also due to lower interest expense on long-term debt resulting from the redemption of high interest rate debt by issuing new debt with lower interest rates. The 2005 decrease also reflects the reversal of approximately $25 million of accrued interest expense as a result of a FERC decision allowing recovery of transmission-related costs (see "Regulatory Matters—Current Regulatory Developments—Transmission Proceeding"), partially offset by interest expense on balancing account overcollections.

Other Nonoperating Deductions

SCE's other nonoperating deductions in 2005 includes an accrual of $22 million for system reliability penalties under a performance incentive mechanism. Based on recorded data through December 2005, SCE expects it will incur a penalty of $22 million under the reliability performance mechanism for 2005. The 2004 increase was mainly due to a $29 million pre-tax charge for the anticipated refund of certain previously received performance incentive rewards, as well as the accrual of $6 million in system reliability penalties (see "Regulatory Matters—Current Regulatory Developments—Investigations Regarding Performance Incentive Rewards").

Minority Interest

Minority interest represents the effects of the adoption of a new accounting pronouncement in second quarter 2004 related to SCE's variable interest entities.

Income Taxes

The composite federal and state statutory income tax rate was approximately 40% for all periods presented. 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. The lower effective tax rate of 32.2% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years. The lower effective tax rate of 30.5% realized in 2003 was primarily due to the resolution of a FERC rate case and recording the benefit of a favorable resolution of tax audit issues.

Income from Discontinued Operations

Earnings from discontinued operations during 2003 include a gain on sale and operating results totaling $50 million from SCE's pipeline business which was sold in the third quarter of 2003.

Historical Cash Flow Analysis

Cash Flows from Operating Activities

Net cash provided by operating activities was $2.4 billion in 2005, $2.3 billion in 2004 and $2.6 billion in 2003. The 2005 change in cash provided by operating activities from continuing operations was mainly due the results from the timing of cash receipts and disbursements related to working capital items. The 2004 decrease in cash provided by operating activities from continuing operations was mainly due to SCE's implementation of a CPUC-approved customer rate reduction plan effective August 1, 2003 and the timing of cash receipts and disbursements related to working capital items.

Cash Flows from Financing Activities

SCE's short-term debt is normally used to working capital requirements. Long-term debt is used mainly to finance the utility's rate base. External financings are influenced by market conditions and other factors.

SCE financing activities in 2005 included activities relating to the rebalancing of SCE's capital structure. SCE's first quarter 2005 financing activity included the issuance of $650 million of first and refunding mortgage bonds. The issuance included $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds 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). SCE's second quarter financing activity included the issuance of $350 million of its 5.35% first and refunding mortgage bond due in 2035 (Series 2005E). A portion of the proceeds was used to redeem $316 million of its 8% first and refunding mortgage bonds due in 2007 (Series 2003B). In addition, in April 2005, SCE issued four million shares of Series A preference stock (non-cumulative, $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 $100 cumulative preferred stock, 7.23% Series, and approximately $64 million of the proceeds was used to redeem all the outstanding shares of its $100 cumulative preferred stock, 6.05% Series. SCE's third quarter 2005 financing activity included the issuance of two million shares of Series B preference stock (non-cumulative, $100 liquidation value) and received net proceeds of approximately $197 million. Financing activities in 2004 also included dividend payments of $214 million to Edison International.

SCE financing activities in 2004 include the issuance of $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034 and $150 million of floating rate bonds due in 2006 all issued during the first quarter of 2004. The proceeds from these issuances were used to call at par $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044. In addition, during the first quarter of 2004, SCE paid the $200 million outstanding balance of its credit facility, as well as remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040. Approximately $354 million of these pollution-control bonds had been held by SCE since 2001 and the remaining $196 million were purchased and reoffered in 2004. In March 2004, SCE issued $300 million of 4.65% first and refunding mortgage bonds due in 2015 and $350 million of 5.75% first and refunding mortgage bonds due in 2035. A portion of the proceeds from the March 2004 first and refunding mortgage bond issuances were used to fund the acquisition and construction of the Mountainview project. During the third quarter, SCE paid $125 million of 5.875% bonds due in September 2004. During the fourth quarter, SCE issued $150 million of floating rate first and refunding mortgage bonds due in 2007. Financing activities in 2004 also included dividend payments of $750 million to Edison International.

SCE's financing activities during 2003 included an exchange offer of $966 million of 8.95% variable rate notes due November 2003 for $966 million of new series first and refunding mortgage bonds due February 2007. In addition, during 2003, SCE repaid $125 million of its 6.25% bonds, the outstanding balance of $300 million of a $600 million one-year term loan due March 3, 2003, $300 million on its revolving line of credit, and $700 million of a term loan due March 2005. The $700 million term loan was retired with a cash payment of $500 million and $200 million drawn on a $700 million credit facility that expires in 2006. SCE's financing activities also include a dividend payment of $945 million to Edison International.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant and funding of nuclear decommissioning trusts.

Investing activities include capital expenditures of $1.8 billion, $1.7 billion and $1.2 billion in 2005, 2004 and 2003, respectively, primarily for transmission and distribution assets, including $166 million related to the Mountainview project and approximately $59 million and $70 million for nuclear fuel acquisitions in 2005 and 2004, respectively. In addition, investing activities in 2004 include $285 million of acquisition costs related to the Mountainview project.

DISPOSITIONS AND DISCONTINUED OPERATIONS

In July 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders. In accordance with an accounting standard related to the impairment and disposal of long-lived assets, this oil storage and pipeline facilities unit's results have been accounted for as a discontinued operation in the 2003 financial statements. For 2003, revenue from discontinued operations was $20 million and pre-tax income was $82 million.

ACQUISITION

In March 2004, SCE acquired Mountainview Power Company LLC, which consisted of a power plant in the early stages of construction in Redlands, California. The Mountainview generating facility is now operating, providing southern California with additional generating capacity of 1,054 MW. As a result, customers will receive over the life of the asset, a $58 million net present value benefit from "bonus" tax depreciation. On January 10, 2006, the FERC accepted the use of the 2005 CPUC-approved rate of return to be applied to the Mountainview power-purchase agreement.

CRITICAL ACCOUNTING ESTIMATES

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

Rate Regulated Enterprises

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of 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 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 (and not challenged) 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, 2005, the consolidated balance sheets included regulatory assets of $3.5 billion and regulatory liabilities of $3.6 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 the accounting standard for derivative instruments and hedging activities, which requires derivative financial instruments to be recorded at their fair value unless an exception applies. The accounting standard 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 ineffective portion of a derivative's change in fair value is immediately recognized in earnings.

Derivative assets and liabilities are shown at gross amounts on the balance sheet, 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.

SCE enters into contracts for power and gas options, as well as swaps, futures and forward contracts 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. Hedge accounting is not used for these transactions. Any fair value changes for recorded derivatives are offset through a regulatory mechanism; therefore, fair value changes do not affect earnings.

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 accounting rules. Leases are not derivatives and are not recorded on the balance sheet unless they are classified as capital leases.

Most of SCE's QF contracts are not required to be recorded on its balance sheet. 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.

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 the fair value of SCE's derivatives under this accounting standard is a critical accounting estimate because the fair value of a derivative is susceptible to significant change resulting from a number of factors, including volatility of energy prices, credits risks, market liquidity and discount rates. See "Market Risk Exposures" for a description of risk management activities and sensitivities to change in market prices.

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.

The accounting standard 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.

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 Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain issues at SCE.

Management continually evaluates its income tax exposures and provides for allowances and/or reserves as appropriate.

Asset Impairment

SCE evaluates long-lived assets whenever indicators of potential impairment exist. Accounting standards require that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

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 asset retirement obligations (ARO) related to the decommissioning of its 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, 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 $11.4 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 that currently receive contributions of approximately $32 million per year. As of December 31, 2005, the decommissioning trust balance was $2.9 billion. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined from an analysis of estimated decommissioning costs, the current value of trust assets and long-term forecasts of cost escalation 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.

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 $186 million at of December 31, 2005 is recorded as an ARO liability.

Pensions and Postretirement Benefits Other than Pensions

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 heath 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 compared the yield curve analysis against the Moody's AA Corporate bond rate. At the December 31, 2005 measurement date, SCE used a discount rate of 5.5% for both pensions and postretirement benefits other than pensions (PBOP).

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 7.1% for PBOP. A portion of PBOP trusts asset returns are subject to taxation, so the 7.1% figure above is determined on an after-tax basis. Actual time-weighted, annualized returns on the pension plan assets were 11.0%, 6.0% and 10.9% for the one-year, five-year and ten-year periods ended December 31, 2005, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 6.3%, 3.3% and 8.3% 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 accounting standards is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2005, this cumulative difference amounted to a regulatory liability of $88 million, meaning that the rate-making method has recognized $88 million more in expense than the accounting method since implementation of the pension accounting standard in 1987.

Under accounting standards, if the accumulated benefit obligation exceeds the market value of plan assets at the measurement date, the difference may result in a reduction to shareholders' equity through a charge to other comprehensive income, but would not affect current net income. The reduction to other comprehensive income would be restored through shareholders' equity in future periods to the extent the market value of trust assets exceeded the accumulated benefit obligation. This assessment is performed annually.

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, 2005, SCE's PBOP plans had a $2.3 billion benefit obligation. Total expense for these plans was $78 million for 2005. The health care cost trend rate is 10.25% for 2006, gradually declining to 5% for 2011 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2005 by $271 million and annual aggregate service and interest costs by $19 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2005 by $243 million and annual aggregate service and interest costs by $17 million.

NEW ACCOUNTING PRINCIPLES

In March 2005, the Financial Accounting Standards Board issued an interpretation related to accounting for conditional ARO. This interpretation 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. This interpretation was effective as of December 31, 2005. SCE identified conditional AROs related to: treated wood poles, hazardous materials such as mercury and polychlorinated biphenyls-containing equipment; and asbestos removal costs at buildings. Since SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates, implementation of this interpretation increased SCE's ARO by $14 million, but did not affect SCE's earnings.

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. SCE is required to implement the new standard in the first quarter of 2006 and will apply the modified prospective transition method. Under the modified prospective method, the new accounting standard will be applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements will not be restated under this method. The new accounting standard will result in the recognition of expense for all stock-based compensation awards; previously, SCE used the intrinsic value method of accounting, at times resulting in no recognition of expense for stock-based compensation.

COMMITMENTS AND INDEMNITIES

SCE's commitments for the years 2006 through 2010 and thereafter are estimated below:

In millions	2006	2007	2008	2009	2010	Thereafter
Long-term debt maturities and sinking fund requirements[1]	$ 823	$ 622	$ 596	$ 210	$ 442	$ 7,044
Fuel supply contract payments	126	64	64	40	47	252
Purchased-power capacity payments	842	775	528	417	393	2,681
Unconditional purchase obligations	5	5	5	5	6	36
Operating lease obligations	192	301	271	213	208	5
Capital lease obligations	3	4	4	4	4	—
Employee benefit plans contributions[2]	128	—	—	—	—	—

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2005, assuming long-term debt is held to maturity, and related forecast interest payments over the applicable period of the debt.

(2) Amount includes estimated contributions to the pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2006 are not available.

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.

Unconditional Purchase Obligations

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 $62 million through 2016 (approximately $6 million per year).

Operating and Capital Leases

SCE has operating leases, primarily for vehicles (with varying terms, provisions and expiration dates). 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 accounting rules. At December 31, 2005, SCE had six power contracts that were classified as operating leases and one power contract that was classified as a capital lease (executed in late 2005).

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. The generating station has not operated since early 2001, and 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.

Other SCE 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.

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and common shareholder's equity present fairly, in all material respects, the financial position of Southern California Edison Company and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for financial instruments with characteristics of both debt and equity as of July 1, 2003, variable interest entities as of March 31, 2004, and asset retirement costs as of December 31, 2005.

Los Angeles, California
March 6, 2006

Consolidated Statements of Income			**Southern California Edison Company**
In millions Year ended December 31,	**2005**	2004	2003
Operating revenue	**$ 9,500**	$ 8,448	$ 8,854
Fuel	**1,193**	810	235
Purchased power	**2,622**	2,332	2,786
Provisions for regulatory adjustment clauses – net	**435**	(201)	1,138
Other operation and maintenance	**2,523**	2,457	2,072
Depreciation, decommissioning and amortization	**915**	860	882
Property and other taxes	**193**	177	168
Net gain on sale of utility property and plant	**(10)**	—	(5)
Total operating expenses	**7,871**	6,435	7,276
Operating income	**1,629**	2,013	1,578
Interest and dividend income	**44**	20	100
Other nonoperating income	**127**	84	72
Interest expense – net of amounts capitalized	**(360)**	(409)	(457)
Other nonoperating deductions	**(65)**	(69)	(23)
Income from continuing operations before tax and minority interest	**1,375**	1,639	1,270
Income tax	**292**	438	388
Minority interest	**334**	280	—
Income from continuing operations	**749**	921	882
Income from discontinued operations – net of tax	**—**	—	50
Net income	**749**	921	932
Dividends on preferred stock subject to mandatory redemption	**—**	—	5
Dividends on preferred stock not subject to mandatory redemption	**24**	6	5
Net income available for common stock	**$ 725**	$ 915	$ 922

Consolidated Statements of Comprehensive Income

In millions Year ended December 31,	**2005**	2004	2003
Net income	**$ 749**	$ 921	$ 932
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment	**(1)**	(1)	(4)
Amortization of cash flow hedges	**2**	3	1
Comprehensive income	**$ 750**	$ 923	$ 929

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

Consolidated Balance Sheets

In millions	December 31,	2005	2004
ASSETS			
Cash and equivalents		**$ 143**	$ 122
Restricted cash		**57**	61
Margin and collateral deposits		**178**	66
Receivables, less allowances of $33 and $31 for uncollectible accounts at respective dates		**849**	618
Accrued unbilled revenue		**291**	320
Inventory		**220**	196
Accumulated deferred income taxes – net		**—**	134
Trading and price risk management asset		**237**	26
Regulatory assets		**536**	553
Prepayments and other current assets		**92**	46
Total current assets		**2,603**	2,142
Nonutility property – less accumulated provision for depreciation of $569 and $554 at respective dates		**1,086**	960
Nuclear decommissioning trusts		**2,907**	2,757
Other investments		**80**	104
Total investments and other assets		**4,073**	3,821
Utility plant, at original cost:			
Transmission and distribution		**16,760**	15,685
Generation		**1,370**	1,356
Accumulated provision for depreciation		**(4,763)**	(4,506)
Construction work in progress		**956**	789
Nuclear fuel, at amortized cost		**146**	151
Total utility plant		**14,469**	13,475
Regulatory assets		**3,013**	3,285
Other long-term assets		**545**	567
Total regulatory assets and other long-term assets		**3,558**	3,852
Total assets		**$ 24,703**	$ 23,290

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

Consolidated Balance Sheets		Southern California Edison Company	
In millions, except share amounts	December 31,	**2005**	2004
LIABILITIES AND SHAREHOLDERS' EQUITY			
Short-term debt		**$ —**	$ 88
Long-term debt due within one year		**596**	246
Preferred stock to be redeemed within one year		**—**	9
Accounts payable		**898**	700
Accrued taxes		**242**	357
Accrued interest		**106**	115
Counterparty collateral		**183**	—
Customer deposits		**183**	168
Book overdrafts		**257**	232
Accumulated deferred income taxes – net		**5**	—
Regulatory liabilities		**681**	490
Other current liabilities		**810**	643
Total current liabilities		**3,961**	3,048
Long-term debt		**4,669**	5,225
Accumulated deferred income taxes – net		**2,815**	2,865
Accumulated deferred investment tax credits		**119**	126
Customer advances and other deferred credits		**550**	510
Power-purchase contracts		**165**	130
Preferred stock subject to mandatory redemption		**—**	139
Accumulated provision for pensions and benefits		**500**	417
Asset retirement obligations		**2,621**	2,183
Regulatory liabilities		**2,962**	3,356
Other long-term liabilities		**284**	232
Total deferred credits and other liabilities		**10,016**	9,958
Total liabilities		**18,646**	18,231
Commitments and contingencies (Notes 8 and 9)			
Minority interest		**398**	409
Common stock, no par value (434,888,104 shares outstanding at each date)		**2,168**	2,168
Additional paid-in capital		**361**	350
Accumulated other comprehensive loss		**(16)**	(17)
Retained earnings		**2,417**	2,020
Total common shareholder's equity		**4,930**	4,521
Preferred and preference stock not subject to mandatory redemption		**729**	129
Total shareholders' equity		**5,659**	4,650
Total liabilities and shareholders' equity		**$ 24,703**	$ 23,290

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

Consolidated Statements of Cash Flows

In millions Year ended December 31,	2005	2004	2003 Revised[1]
Cash flows from operating activities:			
Net income	**$ 749**	$ 921	$ 932
Less: income from discontinued operations	**—**	—	(50)
Income from continuing operations	**749**	921	882
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**915**	860	882
Other amortization	**96**	90	101
Minority interest	**334**	280	—
Deferred income taxes and investment tax credits	**34**	514	(104)
Regulatory assets – long-term	**387**	442	535
Regulatory liabilities – long-term	**(168)**	(69)	(48)
Other assets	**46**	(44)	117
Other liabilities	**72**	18	(364)
Margin and collateral deposits – net of collateral received	**70**	(33)	5
Receivables and accrued unbilled revenue	**(202)**	(9)	185
Trading and price risk management assets	**(211)**	(23)	113
Inventory, prepayments and other current assets	**(66)**	13	(35)
Regulatory assets – short-term	**17**	(254)	13,268
Regulatory liabilities – short-term	**192**	(169)	(12,486)
Accrued interest and taxes	**(126)**	(111)	(223)
Accounts payable and other current liabilities	**251**	(152)	(181)
Operating cash flows from discontinued operations	**—**	—	(34)
Net cash provided by operating activities	**2,390**	2,274	2,613
Cash flows from financing activities:			
Long-term debt issued and issuance costs	**980**	1,747	(11)
Long-term debt repaid	**(1,040)**	(966)	(1,263)
Bonds remarketed – net	**—**	350	—
Issuance of preference stock	**591**	—	—
Redemption of preferred stock	**(148)**	(2)	(6)
Rate reduction notes repaid	**(246)**	(246)	(246)
Short-term debt financing – net	**(88)**	(112)	(4)
Change in book overdrafts	**25**	43	65
Shares purchased for stock-based compensation	**(115)**	(60)	(13)
Proceeds from stock option exercises	**53**	29	3
Minority interest	**(345)**	(290)	—
Dividends paid	**(234)**	(756)	(955)
Net cash used by financing activities	**(567)**	(263)	(2,430)
Cash flows from investing activities:			
Capital expenditures	**(1,808)**	(1,678)	(1,153)
Acquisition costs related to nonutility generation plant	**—**	(285)	—
Proceeds from sale of discontinued operations	**—**	—	146
Proceeds from nuclear decommissioning trust sales	**2,067**	2,416	2,200
Purchases of nuclear decommissioning trust investments	**(2,159)**	(2,525)	(2,286)
Customer advances for construction and other investments	**98**	9	13
Net cash used by investing activities	**(1,802)**	(2,063)	(1,080)
Effect of consolidation of variable interest entities	**—**	79	—
Net increase (decrease) in cash and equivalents	**21**	27	(897)
Cash and equivalents, beginning of year	**122**	95	992
Cash and equivalents, end of year–continuing operations	**$ 143**	$ 122	$ 95

[1] See "Revisions" in Note 1 for further explanation.

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

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 2002	$ 2,168	$ 340	$ (16)	$ 1,892	$ 4,384
Net income				932	932
Minimum pension liability adjustment			(7)		(7)
Tax effect			3		3
Amortization of cash flow hedges			2		2
Tax effect			(1)		(1)
Dividends declared on common stock				(945)	(945)
Dividends declared on preferred stock subject to mandatory redemption				(5)	(5)
Dividends declared on preferred stock not subject to mandatory redemption				(5)	(5)
Shares purchased for stock-based compensation		(9)		(4)	(13)
Proceeds from stock option exercises				3	3
Non-cash stock-based compensation		5			5
Capital stock expense and other		2			2
Balance at December 31, 2003	$ 2,168	$ 338	$ (19)	$ 1,868	$ 4,355
Net income				921	921
Minimum pension liability adjustment			(1)		(1)
Amortization of cash flow hedges			5		5
Tax effect			(2)		(2)
Dividends declared on common stock				(750)	(750)
Dividends declared on preferred stock not subject to mandatory redemption				(6)	(6)
Shares purchased for stock-based compensation		(17)		(43)	(60)
Proceeds from stock option exercises				29	29
Non-cash stock-based compensation		30			30
Capital stock expense and other		(1)		1	—
Balance at December 31, 2004	$ 2,168	$ 350	$ (17)	$ 2,020	$ 4,521
Net income				749	749
Minimum pension liability adjustment			(2)		(2)
Tax effect			1		1
Amortization of cash flow hedges			4		4
Tax effect			(2)		(2)
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
Non-cash stock-based compensation		11			11
Tax benefit related to stock-based awards		29			29
Capital stock expense and other		(10)		(1)	(11)
Balance at December 31, 2005	$ 2,168	$ 361	$ (16)	$ 2,417	$ 4,930

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 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

Southern California Edison Company (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 variable interest entities (VIEs) for which SCE is the primary beneficiary. Effective March 31, 2004, SCE began consolidating four cogeneration projects for which SCE typically purchases 100% of the energy produced under long-term power-purchase agreements, in accordance with a new accounting standard for the consolidation of variable interest entities. Intercompany transactions have been eliminated.

SCE's accounting policies conform to accounting principles generally accepted in the United States, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

Certain prior-year amounts were reclassified to conform to the December 31, 2005 financial statement presentation.

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and Notes. Actual results could differ from those estimates. Certain significant estimates related to financial instruments, income taxes, pensions and postretirement benefits other than pensions, decommissioning and contingencies are further discussed in Notes 2, 5, 6, 8 and 9 to the Consolidated Financial Statements, respectively.

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

Cash Equivalents

Cash equivalents include original maturities of three months or less. Cash equivalents include other investments of $16 million at December 31, 2005. There were no cash equivalents at December 31, 2004. In addition, at December 31, 2005 and 2004, the VIE segment had $120 million and $90 million of cash and equivalents, respectively. For a discussion of restricted cash, see "Restricted Cash".

Debt and Equity Investments

SCE has debt and equity investments for the nuclear decommissioning trust funds. Unrealized gains and losses on decommissioning trust funds increase or decrease the related regulatory asset or liability. All investments are classified as available-for-sale.

Dividend Restriction

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. SCE's authorized capital structure includes a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At

December 31, 2005, SCE's 13-month weighted-average common equity component of total capitalization was 50%. At December 31, 2005, SCE had the capacity to pay $197 million in additional dividends based on the 13-month weighted-average method. Based on recorded December 31, 2005 balances, SCE's common equity to total capitalization ratio was 50.2% for ratemaking purposes. SCE had the capacity to pay $212 million of additional dividends to Edison International based on December 31, 2005 recorded balances.

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.

Margin and Collateral Deposits

Margin and collateral deposits include margin requirements and cash deposited with counterparties and brokers as credit support under margining agreements for power and gas price risk management activities. 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

In March 2005, the Financial Accounting Standards Board issued an interpretation related to accounting for conditional asset retirement obligations (ARO). This interpretation 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. This interpretation was effective as of December 31, 2005. SCE identified conditional AROs related to: treated wood poles, hazardous materials such as mercury and polychlorinated biphenyls-containing equipment; and asbestos removal costs at buildings. Since SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates, implementation of this interpretation at SCE did not affect earnings.

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. SCE is required to implement the new standard in the first quarter of 2006 and will apply the modified prospective transition method. Under the modified prospective method, the new accounting standard will be applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements will not be restated under this method. The new accounting standard will result in the recognition of expense for all stock-based compensation awards; previously, SCE used the intrinsic value method of accounting, at times resulting in no recognition of expense for stock-based compensation.

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	**2005**	2004	2003
Allowance for funds used during construction	**$ 25**	$ 35	$ 27
Performance-based incentive awards	**33**	31	21
Demand-side management and energy efficiency performance incentives	**45**	—	—
Other	**24**	18	24
Total other nonoperating income	**$ 127**	$ 84	$ 72
Various penalties	**$ 27**	$ 35	$ —
Other	**38**	34	23
Total other nonoperating deductions	**$ 65**	$ 69	$ 23

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. All such 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 an allowance for funds used during construction (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 3.9% for 2005, 3.9% for 2004 and 4.3% for 2003.

AFUDC – equity was $25 million in 2005, $23 million in 2004 and $21 million in 2003. AFUDC – debt was $14 million in 2005, $12 million in 2004 and $6 million in 2003.

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.

Effective January 1, 2004, San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 returned to traditional cost-of-service ratemaking. The July 8, 2004 CPUC decision on SCE’s 2003 general rate case returned Palo Verde Nuclear Generating Station (Palo Verde) to traditional cost-of-service ratemaking retroactive to May 22, 2003 (the date a final CPUC decision was originally scheduled to be issued). As authorized by the CPUC, SCE had been recovering its investments in San Onofre and Palo Verde on an accelerated basis; these units also had incentive rate-making plans.

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 of SCE's property, plant and equipment, as authorized by the CPUC, are as follows:

Generation plant	38 years to 81 years
Distribution plant	24 years to 53 years
Transmission plant	40 years to 60 years
Other plant	5 years to 40 years

Nuclear fuel is recorded as utility plant in accordance with CPUC rate-making procedures.

Nonutility Property

Nonutility property, including construction in progress, is capitalized at cost, including interest accrued on borrowed funds that finance construction. Capitalized interest was $16 million in 2005, $9 million in 2004, and zero in 2003. The Mountainview power plant is included in nonutility property in accordance with the rate-making treatment.

Depreciation and amortization is primarily computed on a straight-line basis over the estimated useful lives of nonutility properties and over the lease term for leasehold improvements. Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 3.6% for 2005. The composite rate for 2004 and 2003 is not disclosed due to the non-comparability of this property in 2003. The VIEs (commenced consolidation in March 31, 2004) compose a majority of nonutility property.

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

In millions December 31,	**2005**	2004
Furniture and equipment	**$ 3**	$ 1
Building, plant and equipment	**1,347**	1,012
Land (including easements)	**34**	31
Construction in progress	**271**	470
	1,655	1,514
Accumulated provision for depreciation	**(569)**	(554)
Nonutility property – net	**$ 1,086**	$ 960

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 20 years
Building, plant and equipment	3 years to 40 years
Land easements	60 years

Asset Retirement Obligations

As a result of an accounting standard adopted 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.

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

In millions	
ARO liability as of December 31, 2003	$ 2,084
Accretion expense	132
Liabilities settled	(33)
ARO liability as of December 31, 2004	2,183
Revisions	117
Liabilities added	14
Accretion expense	366
Liabilities settled	(59)
ARO liability as of December 31, 2005	$ 2,621
Fair value of nuclear decommissioning trusts	$ 2,907

Since SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates; therefore implementation of this new standard and the subsequent interpretation did not affect SCE's earnings. The pro forma disclosures for conditional AROs are not shown due to the immaterial impact on SCE's consolidated balance sheet. See "New Accounting Pronouncements" above.

Purchased Power

From January 17, 2001 to December 31, 2002, the California Department of Water Resources (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, as determined by the average percentage of amounts written-off in prior accounting periods. SCE assesses its customers a late fee of 0.9% per month, beginning 19 days after the bill is prepared. Inactive accounts are written off after 180 days.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, 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.

Included in these regulatory assets and liabilities are SCE's 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 adjustment clauses.

Regulatory Assets

Regulatory assets included in the consolidated balance sheets are:

In millions December 31,	2005	2004
Current:		
Regulatory balancing accounts	**$ 355**	$ 371
Direct access procurement charges	**113**	109
Purchased-power settlements	**53**	62
Other	**15**	11
	536	553
Long-term:		
Flow-through taxes – net	**1,066**	1,018
Rate reduction notes – transition cost deferral	**465**	739
Unamortized nuclear investment – net	**487**	526
Nuclear-related ARO investment – net	**292**	272
Unamortized coal plant investment – net	**97**	78
Unamortized loss on reacquired debt	**323**	250
Direct access procurement charges	**40**	141
Environmental remediation	**56**	55
Purchased-power settlements	**39**	91
Other	**148**	115
	3,013	3,285
Total Regulatory Assets	**$ 3,549**	$ 3,838

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 will be collected by mid-2007. SCE's regulatory assets related to purchased-power settlements will be recovered through 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 regulatory asset related to the rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and is expected to be recovered by the end of 2007. SCE's nuclear-related regulatory assets are expected to be recovered by the end of the remaining useful lives of the nuclear facilities. SCE has requested a four-year recovery period for the net regulatory asset related to its unamortized coal plant investment. CPUC approval is pending. SCE's 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 environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

SCE earns a return on three of the regulatory assets listed above: unamortized nuclear investment – net, unamortized coal plant investment – net and unamortized loss on reacquired debt.

Regulatory Liabilities

Regulatory liabilities included in the consolidated balance sheets are:

In millions December 31,	2005	2004
Current:		
Regulatory balancing accounts	**$ 370**	$ 357
Direct access procurement charges	**113**	109
Energy derivatives	**136**	—
Other	**62**	24
	681	490
Long-term:		
ARO	**584**	819
Costs of removal	**2,110**	2,112
Direct access procurement charges	**39**	141
Employee benefits plans	**229**	200
Other	**—**	84
	2,962	3,356
Total Regulatory Liabilities	**$ 3,643**	$ 3,846

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 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. SCE's regulatory liabilities related to employee benefit plan expenses represent pension and postretirement benefits other than pensions 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 applied as otherwise directed by the CPUC.

Related Party Transactions

Four Edison Mission Energy (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 "Variable Interest Entities").

SCE holds $153 million in notes receivable from affiliates, due in June 2007. The notes were issued by Edison International in second quarter 1997, and assigned to SCE in fourth quarter 1997. A $78 million note receivable from EME with an interest rate of LIBOR plus 0.275%; and a 4.4%, $75 million note receivable from Edison Capital. The amounts are in long-term assets 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.

Revenue

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. Revenue related to SCE's transmission function is authorized by the FERC in periodic proceedings that are similar to the CPUC's proceedings, except that requested rate changes are generally implemented when the application is filed, and revenue collected prior to a final FERC decision is subject to refund. Rates include amounts for current period costs, plus the recovery of certain previously incurred costs. However, in accordance with accounting standards for rate-regulated enterprises, amounts currently authorized in rates for recovery of costs to be incurred in the future are not recognized as revenue until the associated costs are incurred. Instead, these amounts are recorded as regulatory liabilities. For costs recovered through CPUC-authorized general rate case rates, costs incurred in excess of revenue billed are deferred in a balancing account, and recovered in future rates.

Since January 17, 2001, power purchased by the CDWR or through the California Independent System Operator (ISO) for SCE's customers is not considered a cost to SCE, because SCE is acting as an agent for these transactions. Further, amounts billed to ($1.9 billion in 2005, $2.5 billion in 2004 and $1.7 billion in 2003) 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.

Revisions

SCE revised its consolidated statements of cash flows for the year ended December 31, 2003 to separately disclose the operating portion of the cash flows attributable to discontinued operations. SCE has previously reported this amount as a net change in cash of discounted operations.

Stock-Based Compensation

SCE has stock-based compensation plans, which are described more fully in Note 6. SCE accounts for those plans using the intrinsic value method. Upon grant, no stock-based compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income if SCE had used the fair-value accounting method.

In millions Year ended December 31,	**2005**	2004	2003
Net income available for common stock, as reported	**$ 725**	$ 915	$ 922
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	**26**	28	7
Less: stock-based compensation expense using the fair-value accounting method – net of tax	**24**	32	9
Pro forma net income available for common stock	**$ 727**	$ 911	$ 920

Supplemental Accumulated Other Comprehensive Loss Information

Supplemental information regarding SCE's accumulated other comprehensive loss is:

In millions December 31,	**2005**	2004
Minimum pension liability – net of tax	**$ (11)**	$ (10)
Unrealized losses on cash flow hedges – net of tax	**(5)**	(7)
Accumulated other comprehensive loss	**$ (16)**	$ (17)

The minimum pension liability is discussed in Note 6, "Compensation and Benefit Plans."

Unrealized losses on cash flow hedges relate to SCE's interest rate swap (the swap terminated on January 5, 2001, but the related debt matures in 2008). The unamortized loss of $5 million (as of December 31, 2005, net of tax) on the interest rate swap will be amortized over a period ending in 2008. Approximately $2 million, after tax, of the unamortized loss on this swap will be reclassified into earnings during 2006.

Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions Year ended December 31,	**2005**	2004	2003
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 330**	$ 342	$ 390
Tax payments	**410**	29	585
Non-cash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	**$ (452)**	—	—
Pollution-control bonds issued	**452**	—	—
Details of obligation under capital lease:			
Capital lease purchased	**$ (15)**	—	—
Capital lease obligation issued	**15**	—	—
Dividends declared but not paid	**$ 81**	—	—
Details of consolidation of variable interest entities:			
Assets	**—**	$ 458	—
Liabilities	**—**	(537)	—
Reoffering of pollution-control bonds	**—**	$ 196	—
Details of pollution-control bonds redemption:			
Release of funds held in trust	**—**	$ 20	—
Pollution-control bonds redeemed	**—**	(20)	—
Details of debt exchange:			
Retirement of senior secured credit facility	**—**	—	$ (700)
Short-term credit facility utilized	**—**	—	200
Cash paid	**—**	—	$ (500)
Details of long-term debt exchange offer:			
Variable rate notes redeemed	**—**	—	$ (966)
First and refunding mortgage bonds issued	**—**	—	966
Obligation to fund investment in acquisition	**—**	—	$ 8

Variable Interest Entities

SCE has variable interests in contracts with certain qualifying facilities (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 effective March 31, 2004. Prior periods have not been restated.

Project	Capacity	Termination Date	EME Ownership
Kern River	300 MW	August 2010	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

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 non-recourse to SCE.

Effective April 1, 2004, the variable interest entities' operating costs are shown in SCE's consolidated statements of income. Prior to that date, purchases under these qualifying facility contracts were reported as purchased-power expense. Further, SCE's operating revenue beginning April 1, 2004, includes revenue from the sale of steam by these four projects. The effect that these variable interest entities have on SCE's consolidated financial statements is shown in Note 10.

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. However, these entities are not legally obligated to provide the financial information to SCE that is necessary to determine whether SCE must consolidate these entities. These eight entities have declined to provide SCE with the necessary financial information. SCE is continuing to attempt to obtain information for these projects in order to determine whether they should be consolidated by SCE. The aggregate capacity dedicated to SCE for these projects is 267 MW. SCE paid $198 million in 2005, $166 million in 2004 and $147 million in 2003 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 2. Derivative Instruments and Hedging Activities

SCE's 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 records its derivative instruments on its consolidated balance sheets at fair value 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 SCE enters into contracts for power and gas options, as well as swaps and futures, in order to mitigate its exposure to increase in natural gas and electricity pricing. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. Hedge accounting is not used for these transactions. Any fair value changes for recorded derivatives are recorded in purchased- power expense and offset through the provision for regulatory adjustment clauses; therefore, fair value changes do not affect earnings.

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 accounting rules. Leases are not derivatives and are not recorded on the consolidated balance sheets unless they are classified as capital leases.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets. For further discussion see "Variable interest entities" in Note 1. 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 balances sheet at fair value.

Derivative assets and liabilities are shown 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 carrying amounts and fair values of financial instruments are:

	December 31,			
	2005		2004	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Interest rate hedges	**$ —**	**$ —**	$ 3	$ 3
Commodity price assets	**239**	**239**	14	14
Commodity price liabilities	**(87)**	**(87)**	(12)	(12)
Other:				
Decommissioning trusts	**2,907**	**2,907**	2,757	2,757
DOE decommissioning and decontamination fees	**(7)**	**(7)**	(13)	(13)
QF power contracts assets	**23**	**23**	—	—
QF power contracts liabilities	**(94)**	**(94)**	(12)	(12)
Long-term debt	**(4,669)**	**(4,812)**	(5,225)	(5,551)
Long-term debt due within one year	**(596)**	**(604)**	(246)	(254)
Preferred stock to be redeemed within one year	**—**	**—**	(9)	(9)
Preferred stock subject to mandatory redemption	**—**	**—**	(139)	(140)

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; quoted market prices for decommissioning trusts; and discounted future cash flows for United States Department of Energy (DOE) decommissioning and decontamination fees.

Due to their short maturities, amounts reported for short-term debt and cash equivalents approximate fair value.

Note 3. Liabilities and Lines of Credit

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security 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, 2005, 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.

Debt premium, discount and issuance expenses are deferred and amortized (on a straight-line basis) through interest expense over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized (on a straight-line basis) 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.

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. 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 is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. 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, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Long-term debt is:

In millions December 31,	**2005**	2004
First and refunding mortgage bonds:		
2006 – 2036 (4.65% to 6.00% and variable)	**$ 2,775**	$ 2,741
Rate reduction notes:		
2006 – 2007 (6.38% to 6.42%)	**493**	739
Pollution-control bonds:		
2008 – 2035 (2.00% to 5.55% and variable)	**1,196**	1,196
Debentures and notes:		
2006 – 2053 (5.00% to 7.625%)	**810**	812
Long-term debt due within one year	**(596)**	(246)
Unamortized debt discount – net	**(9)**	(17)
Total	**$ 4,669**	$ 5,225

Note: Rates and terms as of December 31, 2005

Long-term debt maturities and sinking-fund requirements for the next five years are: 2006 – $596 million; 2007 – $396 million; 2008 – $385 million; 2009 – zero; and 2010 – $250 million.

At December 31, 2005 and 2004 SCE had a credit line with a limit of $1.7 billion and $700 million, respectively. At December 31, 2005, SCE had $1.52 billion in available credit under its credit line. At December 31, 2004, SCE had $602 million in available credit under its credit line. There was no outstanding short-term debt at December 31, 2005. At December 31, 2004 the outstanding short-term debt and weighted-average interest rate was $88 million at 2.48%.

In January 2006, SCE issued $500 million of first and refunding mortgage bonds. The issuance included $350 million of 5.625% bonds due in 2036 and $150 million of variable rate bonds due in 2009.

SCE has 12 million authorized shares of preferred stock. These shares can be issued with or without mandatory redemption requirements – see Note 4. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. Mandatorily redeemable preferred stock is subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid, if any, are charged to expense.

At December 31, 2005, SCE had no preferred stock subject to mandatory redemption. At December 31, 2004, SCE's $100 par value cumulative preferred stock subject to mandatory redemption consisted of: $58 million (net of $9 million of preferred stock to be redeemed within one year) of preferred stock for Series 6.05% and $81 million for Series 7.23%.

The 6.05% Series preferred stock had mandatory sinking funds, requiring SCE to redeem at least 37,500 shares per year from 2003 through 2007, and 562,500 shares in 2008. SCE was allowed to credit previously repurchased shares against the mandatory sinking-fund provisions. In 2005, SCE redeemed 673,800 shares of 6.05% Series cumulative preferred stock, which included 36,300 shares redeemed to satisfy the mandatory sinking-fund requirement. In 2004, SCE repurchased 20,000 shares of 6.05% Series preferred stock.. In 2003, SCE repurchased 56,200 shares of 6.05% Series preferred stock. At December 31, 2004, SCE had 1,200 previously repurchased, but not retired, shares available to credit against the mandatory sinking-fund provisions.

The 7.23% Series preferred stock also has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE was allowed to credit previously repurchased shares against the mandatory sinking-fund provisions. In 2005, SCE redeemed the remaining 807,000 shares of 7.23% Series cumulative preferred stock. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2004 or 2003. At December 31, 2004, SCE had 43,000 previously repurchased, but not retired, shares available to credit against the mandatory sinking-fund provisions.

Note 4. Preferred and Preference Stock Not Subject to Mandatory Redemption

SCE's authorized shares are: $100 cumulative preferred – 12 million, $25 cumulative preferred – 24 million and preference – 50 million. 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 last three years. There is no sinking fund redemption or repurchase of the 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 non-cumulative 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, 2005 Shares Outstanding	December 31, 2005 Redemption Price	**2005**	2004
Cumulative preferred stock:				
$25 par value:				
4.08% Series	1,000,000	$ 25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Preference stock:				
No par value:				
5.349% Series A	4,000,000	100.00	**400**	—
6.125% Series B	2,000,000	100.00	**200**	—
Total			**$ 729**	$ 129

The Series A preference stock 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 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.

In January 2006, SCE issued two million shares of 6.0% Series C preference stock (non-cumulative, $100 liquidation value). The Series C preference stock 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. The Series C preference stock has the same general characteristics as the Series A and B preference stock mentioned above.

Note 5. 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.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are amortized over the lives of the related properties.

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

In millions Year ended December 31,	**2005**	2004	2003
Current:			
Federal	**$ 255**	$ (88)	$ 408
State	**84**	46	174
	339	(42)	582
Deferred:			
Federal	**(18)**	425	(134)
State	**(29)**	55	(60)
	(47)	480	(194)
Total	**$ 292**	$ 438	$ 388

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

In millions December 31,	**2005**	2004
Deferred tax assets:		
Accrued charges	**$ 117**	$ 200
Investment tax credits	**72**	64
Property-related	**352**	196
Regulatory balancing accounts	**301**	321
Unrealized gains and losses	**321**	392
Decommissioning	**163**	84
Pensions and postretirement benefits other than pensions	**182**	125
Other	**409**	120
Total	**$ 1,917**	$ 1,502
Deferred tax liabilities:		
Property-related	**$ 3,184**	$ 2,915
Capitalized software costs	**173**	164
Regulatory balancing accounts	**607**	710
Unrealized gains and losses	**321**	289
Decommissioning	**125**	31
Other	**327**	124
Total	**$ 4,737**	$ 4,233
Accumulated deferred income taxes – net	**$ 2,820**	$ 2,731
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$ 2,815**	$ 2,865
Included in current assets	**—**	134
Included in current liabilities	**5**	—

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

Year ended December 31,	**2005**	2004	2003
Federal statutory rate	**35.0%**	35.0%	35.0%
Tax reserve adjustments	**(2.1)**	(7.3)	(2.8)
Resolution of 1991-1993 audit cycle	**(5.8)**	—	—
Resolution of FERC rate case	**—**	—	(5.9)
Property-related	**(0.5)**	0.4	0.1
State tax – net of federal deduction	**3.2**	4.8	6.0
Other	**(1.7)**	(0.7)	(1.9)
Effective tax rate	**28.1%**	32.2%	30.5%

The composite federal and state statutory income tax rate was approximately 40% for all periods presented. The lower effective tax rate of 28.1% realized in 2005 was primarily due to settlement of the 1991-1993 Internal Revenue Service (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. The lower effective tax rate of 32.2% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years. The lower effective tax rate of 30.5% realized in 2003 was primarily due to the resolution of a FERC rate case and recording the benefit of a favorable resolution of tax audit issues.

As a matter of course, SCE is regularly audited by federal and state taxing authorities. For further discussion of this matter, see "Federal Income Taxes" in Note 9.

Note 6. 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 $51 million in 2005, $37 million in 2004 and $33 million in 2003.

Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

Defined benefit pension plans (some with cash balance features) cover employees meeting minimum service requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking.

At December 31, 2005 and December 31, 2004, the accumulated benefit obligations of the executive pension plans exceeded the related plan assets at the measurement dates. In accordance with accounting standards, SCE's consolidated balance sheets include an additional minimum liability, with corresponding charges to intangible assets and shareholder's equity (through a charge to accumulated other comprehensive income). The charge to accumulated other comprehensive income would be restored through shareholder's equity in future periods to the extent the fair value of the plan assets exceed the accumulated benefit obligation.

The expected contributions (all by the employer) are approximately $51 million for the year ended December 31, 2006. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

SCE uses a December 31 measurement date for all of its plans. The fair value of plan assets is determined by market value.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2005**	2004
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 3,033**	$ 2,809
Service cost	**99**	86
Interest cost	**166**	162
Amendments	**2**	22
Actuarial loss	**103**	106
Benefits paid	**(181)**	(152)
Projected benefit obligation at end of year	**$ 3,222**	$ 3,033
Accumulated benefit obligation at end of year	**$ 2,791**	$ 2,627
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 2,981**	$ 2,779
Actual return on plan assets	**297**	316
Employer contributions	**6**	38
Benefits paid	**(181)**	(152)
Fair value of plan assets at end of year	**$ 3,103**	$ 2,981
Funded status	**$ (119)**	$ (52)
Unrecognized net loss	**113**	105
Unrecognized transition obligation	**—**	1
Unrecognized prior service cost	**76**	91
Recorded asset	**$ 70**	$ 145
Additional detail of amounts recognized in balance sheets:		
Intangible asset	**$ 2**	$ 2
Accumulated other comprehensive income	**(19)**	(16)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 101**	$ 77
Accumulated benefit obligation	**85**	61
Fair value of plan assets	**—**	—
Weighted-average assumptions at end of year:		
Discount rate	**5.5%**	5.5%
Rate of compensation increase	**5.0%**	5.0%

Expense components are:

In millions Year ended December 31,	**2005**	2004	2003
Service cost	**$ 99**	$ 86	$ 79
Interest cost	**166**	162	162
Expected return on plan assets	**(215)**	(201)	(187)
Special termination benefits	**—**	—	3
Net amortization and deferral	**21**	22	34
Expense under accounting standards	**71**	69	91
Regulatory adjustment – deferred	**(26)**	(26)	(44)
Total expense recognized	**$ 45**	$ 43	$ 47
Change in accumulated other comprehensive income	**$ (3)**	$ —	$ (7)
Weighted-average assumptions:			
Discount rate	**5.5%**	6.0%	6.5%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected return on plan assets	**7.5%**	7.5%	8.5%

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

In millions Year ended December 31,	
2006	$ 237
2007	251
2008	264
2009	274
2010	285
2011–2015	1,532

Asset allocations are:

	Target for 2006	December 31, **2005**	2004
United States equity	45%	**47%**	47%
Non-United States equity	25	**26**	25
Private equity	4	**2**	2
Fixed income	26	**25**	26

Postretirement Benefits Other Than Pensions

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.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. SCE adopted a new accounting pronouncement for the effects of the Act, effective July 1, 2004, which reduced SCE's accumulated benefits obligation by $116 million upon adoption.

The expected contributions (all by the employer) to the postretirement benefits other than pensions trust are $77 million for the year ended December 31, 2006. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

SCE uses a December 31 measurement date. The fair value of plan assets is determined by market value.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2005**	2004
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,146**	$ 2,137
Service cost	**44**	40
Interest cost	**118**	123
Amendments	**(15)**	28
Actuarial loss (gain)	**38**	(88)
Benefits paid	**(56)**	(94)
Benefit obligation at end of year	**$ 2,275**	$ 2,146
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,465**	$ 1,389
Actual return on plan assets	**92**	145
Employer contributions	**72**	25
Benefits paid	**(56)**	(94)
Fair value of plan assets at end of year	**$ 1,573**	$ 1,465
Funded status	**$ (702)**	$ (681)
Unrecognized net loss	**842**	841
Unrecognized prior service cost	**(271)**	(285)
Recorded liability	**$ (131)**	$ (125)
Assumed health care cost trend rates:		
Rate assumed for following year	**10.25%**	10.0%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2011**	2010
Weighted-average assumptions at end of year:		
Discount rate	**5.5%**	5.75%

Expense components are:

In millions Year ended December 31,	**2005**	2004	2003
Service cost	**$ 44**	$ 40	$ 42
Interest cost	**118**	123	122
Expected return on plan assets	**(101)**	(96)	(89)
Special termination benefits	**—**	—	1
Amortization of unrecognized prior service costs	**(28)**	(29)	(20)
Amortization of unrecognized loss	**45**	49	52
Amortization of unrecognized transition obligation	**—**	—	9
Total expense	**$ 78**	$ 87	$ 117
Assumed health care cost trend rates:			
Current year	**10.0%**	12.0%	9.75%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2010**	2010	2008
Weighted-average assumptions:			
Discount rate	**5.75%**	6.25%	6.4%
Expected return on plan assets	**7.1%**	7.1%	8.2%

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2005 by $271 million and annual aggregate service and interest costs by $19 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2005 by $243 million and annual aggregate service and interest costs by $17 million.

The following benefit payments are expected to be paid:

In millions Year ended December 31,	Before Subsidy	Net
2006	$ 104	$ 99
2007	113	107
2008	118	111
2009	127	120
2010	135	127
2011–2015	760	711

Asset allocations are:

	Target for 2006	December 31, **2005**	2004
United States equity	64%	**65%**	64%
Non-United States equity	16	**14**	14
Fixed income	20	**21**	22

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

Non-United States Equity: 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 non-publicly 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, capital markets return forecasts for asset classes employed, and active management excess return expectations. A portion of postretirement benefits other than pensions 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 non-government 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.

Active Management Excess Return Expectations

For asset classes that are actively managed, an excess return premium is added to the capital market return forecasts discussed above.

Stock-Based Compensation

Under various plans, SCE may grant stock options at exercise prices equal to the market price at the grant date and other awards based on Edison International common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of up to five years, with expense accruing evenly over the vesting period. Edison International has approximately 12.5 million shares remaining for future issuance under equity compensation plans.

Most Edison International stock options issued prior to 2000 accrue dividend equivalents, subject to certain performance criteria. The 2003, 2004, and 2005 options accrue dividend equivalents for the first five years of the option term. Unless deferred, dividend equivalents accumulate without interest.

The fair value for each option granted, reflecting the basis for the pro forma disclosures in Note 1, was determined as of the grant date using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	**2005**	2004	2003
Expected years until exercise	**9 – 10**	9 – 10	10
Risk-free interest rate	**4.1% – 4.3%**	4.0% – 4.3%	3.8% – 4.5%
Expected dividend yield	**2.1% – 3.1%**	2.7% – 3.7%	1.8%
Expected volatility	**15% – 20%**	19% – 22%	44% – 53%

A summary of the status of Edison International stock options is as follows:

	Share Options	Weighted-Average Exercise Price	Weighted-Average Fair Value At Grant
Outstanding, Dec. 31, 2002	6,810,798	$ 22.37	
Granted	2,076,070	12.41	$ 7.34
Expired	(115,612)	22.98	
Forfeited	(59,473)	15.34	
Exercised	(156,697)	18.71	
Outstanding, Dec. 31, 2003	8,555,086	$ 20.06	
Granted	2,476,820	21.98	$ 6.61
Expired	(509)	16.23	
Forfeited	(79,536)	16.83	
Exercised	(1,589,948)	18.20	
Outstanding, Dec. 31, 2004	9,361,913	$ 20.91	
Granted	1,848,039	32.26	$ 9.40
Expired	—	—	
Forfeited	(162,606)	21.02	
Exercised	(2,460,098)	21.67	
Outstanding, Dec. 31, 2005	8,587,248	$ 23.22	

A summary of stock options outstanding at December 31, 2005 is as follows:

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Years of Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$ 8.90–$13.99	1,539,416	7	$ 12.22	717,388	$ 12.16
$14.00–$20.99	1,174,081	6	$ 18.55	811,701	$ 18.52
$21.00–$31.49	4,016,320	6	$ 24.62	2,262,774	$ 26.66
$31.50–$46.87	1,857,431	9	$ 32.26	51,206	$ 31.94
Total	8,587,248	7	$ 23.22	3,843,069	$ 22.31

The number of options exercisable and their weighted-average exercise prices at December 31, 2004 and 2003 were 4,546,711 at $23.69 and 4,845,967 at $24.06, respectively.

Performance shares were awarded to executives in January 2003, January 2004 and January 2005 and vest at the end of December 2005, 2006 and 2007, respectively. The number of common shares paid out from the performance share awards depends on the performance of Edison International common stock relative to the stock performance of a specified group of companies. Performance share values are accrued ratably over the vesting period based on the value of the underlying Edison International common stock. The number of performance shares granted and their weighted-average grant-date value for 2005, 2004 and 2003 were 132,655 at $32.07, 178,684 at $21.94, and 293,497 at $12.33, respectively. In the pro forma disclosure reflected in Note 1, the portions of these performance shares settled in stock, which were half of the total shares outstanding, were treated as equity awards. The weighted-average grant-date fair values of these performance shares were $46.09, $33.62 and $21.42, for 2005, 2004 and 2003, respectively.

See Note 1 for SCE's accounting policy and expenses related to stock-based compensation.

Note 7. Jointly Owned Utility Projects

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

SCE's investment in each project as of December 31, 2005 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 60	$ 9	60%
Pacific Intertie	306	80	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	499	407	48
Mohave (coal)	350	269	56
Palo Verde (nuclear)	1,710	1,468	16
San Onofre (nuclear)	4,522	3,956	75
Total	$ 7,447	$ 6,189	

All of Mohave Generating Station and a portion of San Onofre and Palo Verde is included in regulatory assets on the consolidated balance sheets. See Note 1. Mohave ceased operations on December 31, 2005. At this time, SCE does not know the length of the shutdown period, and a permanent shutdown remains possible.

Note 8. Commitments

Leases

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 accounting rules. At December 31, 2005, SCE had six power contracts that were classified as operating leases and one capital lease (executed in late 2005). Operating lease expense for power purchases was $68 million in 2005 and zero for all other periods presented. Other operating lease expense, primarily for vehicle leases, was $20 million in 2005, $17 million in 2004, and $15 million in 2003. The leases have varying terms, provisions and expiration dates. The capital lease (net commitment of $15 million) is reported as a long-term obligation on the consolidated balance sheet under the caption, other long-term liabilities.

Estimated remaining commitments for noncancelable operating leases at December 31, 2005 are:

In millions	Year ended December 31,	Power Contracts Operating Leases	Other Operating Leases
2006		$ 177	$ 15
2007		288	13
2008		260	11
2009		205	8
2010		204	4
Thereafter		—	5
Total		$ 1,134	$ 56

Nuclear Decommissioning

As a result of an accounting standard adopted 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 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 decommissioning SCE's nuclear power facilities is $2.6 billion as of December 31, 2005, 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 $11.4 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 October 2003 receive contributions of approximately $32 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 4.5% to 5.6%. If the assumed return on trust assets is not earned, additional funds needed for decommissioning will be recoverable through rates.

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 ($186 million at December 31, 2005). Total expenditures for the decommissioning of San Onofre Unit 1 were $414 million from the beginning of the project in 1998 through December 31, 2005.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. 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 2025, 2026 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 created under this new standard, are deferred as increases to the ARO regulatory liability account, with no impact on earnings.

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

Decommissioning expense under the rate-making method was $118 million in 2005, $125 million in 2004 and $118 million in 2003. The ARO for decommissioning SCE's active nuclear facilities was $2.4 billion at December 31, 2005 and $2.0 billion at December 31, 2004.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments (at fair value) include:

In millions	Maturity Dates	December 31,	**2005**	2004
Municipal bonds	2006 – 2039		**$ 863**	$ 784
Stock	–		**1,451**	1,403
United States government issues	2006 – 2035		**479**	485
Corporate bonds	2006 – 2045		**42**	41
Short-term	2006		**72**	44
Total			**$ 2,907**	$2,757

Note: Maturity dates as of December 31, 2005.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (loss) were $87 million in 2005, $91 million in 2004, and $93 million in

2003. Proceeds from sales of securities (which are reinvested) were $2.0 billion in 2005, $2.5 billion in 2004, and $2.2 billion in 2003. Net unrealized holding gains were $852 million and $796 million at December 31, 2005 and 2004, respectively. Approximately 91% 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 2006 through 2010 are estimated below:

In millions	2006	2007	2008	2009	2010
Fuel supply	$126	$ 64	$ 64	$ 40	$ 47
Purchased power	842	775	528	417	393

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 $62 million through 2016 (approximately $6 million per year).

Indemnities

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. The generating station has not operated since 2001. 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.

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.

Note 9. 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 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.

SCE's recorded estimated minimum liability to remediate its 24 identified sites is $82 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $115 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 had 31 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $30 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 $56 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 $25 million. Recorded costs for 2005 were $13 million.

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 Income Taxes

Edison International has reached a settlement with the IRS on tax issues and pending affirmative claims relating to its 1991–1993 tax years. This settlement, which was signed by Edison International in March 2005 and approved by the United States Congress Joint Committee on Taxation on July 27, 2005, resulted in a third quarter 2005 net earnings benefit for SCE of approximately $61 million, including interest. This benefit was reflected in the caption "Income tax" on the consolidated statements of income.

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would benefit SCE as future tax deductions.

The IRS Revenue Agent Report for the 1997–1999 audit also 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. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

FERC Refund Proceedings

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the California Power Exchange (PX) and ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. 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. SCE is required to refund to customers 90% of any refunds actually realized by SCE net of litigation costs, except for the El Paso Natural Gas Company settlement agreement discussed below, and 10% will be retained by SCE as a shareholder incentive. A brief summary of the various settlements is below:

- In June 2004, SCE received its first settlement payment of $76 million resulting from a settlement agreement with El Palo Natural Gas Company. Approximately $66 million of this amount was credited to purchased-power expense, and was refunded to SCE's ratepayers through the energy resource recovery account (ERRA) mechanism over the following twelve months, and the remaining $10 million was used to offset SCE's incurred legal costs. In May 2005, SCE received its final settlement payment of $66 million, which was also refunded to ratepayers through the ERRA mechanism.

- In August 2004, SCE received its $37 million share of settlement proceeds resulting from a FERC-approved settlement agreement with The Williams Cos. and Williams Power Company.

- In November 2004, SCE received its $42 million share of settlement proceeds resulting from a FERC-approved settlement agreement with West Coast Power, LLC and its owners, Dynegy Inc. and NRG Energy, Inc.

- In January 2005, SCE received its $45 million share of settlement proceeds resulting from a FERC-approved settlement agreement with Duke Energy Corporation and a number of its affiliates.

- In April 2005, the FERC approved a settlement agreement among SCE, Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E) and several governmental entities, and Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in Chapter 11 bankruptcy proceedings pending in Texas. In April and May 2005, SCE received its $68 million share of the cash portion of the settlement proceeds. SCE also received a $33 million share of an allowed, unsecured claim in the bankruptcy of one of the Mirant parties which was sold for $35 million in December 2005.

- In November 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E and several governmental entities, and Enron Corporation and a number of its affiliates (collectively Enron), most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In January 2006, SCE received cash settlement proceeds of $4 million and anticipates receiving approximately $5 million in additional cash proceeds assuming certain contingencies are satisfied. SCE also received an allowed, unsecured claim against one of the Enron debtors in the amount of $241 million. In February 2006, SCE received a partial distribution of $10 million of its allowed claim. The remaining amount of the allowed claim that will actually be realized will depend on events in Enron's bankruptcy that impact the value of the relevant debtor estate.

- In December 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E, several governmental entities and certain other parties, and Reliant Energy, Inc. and a number of its affiliates (collectively Reliant). In January 2006, SCE received its $65 million share of the settlement proceeds. SCE expects to receive an additional $66 million in the first quarter of 2006.

On November 19, 2004, the CPUC issued a resolution authorizing SCE to establish an energy settlement memorandum account (ESMA) for the purpose of recording the foregoing settlement proceeds (excluding the El Paso settlement) from energy providers and allocating them in accordance with a settlement agreement. The resolution provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA are allocated to recovery of SCE's litigation costs and expenses in the FERC refund proceedings described above and the 10% shareholder incentive. Remaining amounts for each settlement are to be refunded to ratepayers through the ERRA mechanism. During 2005, SCE recognized $23 million in shareholder incentives related to the FERC refunds described above.

Investigations Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based ratemaking (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 has been conducting investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below. As a result of the reported events, the CPUC could institute its own proceedings to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, injury and illness reporting, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE. SCE cannot predict with certainty the outcome of these matters or estimate the potential amount of refunds, disallowances, and penalties that may be required.

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 to SCE under the PBR provisions for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 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. As a result of these findings, SCE accrued a $9 million charge in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by severing the employment of 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 general rate case.

The CPUC has not yet opened a formal investigation into this matter. However, it has submitted several data requests to SCE and has requested an opportunity to interview a number of SCE employees in the design organization. SCE has responded to these requests and the CPUC has conducted interviews of approximately 20 employees who were disciplined for misconduct and four senior managers and executives of the transmission and distribution business unit.

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 received $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 for any year before 2005, and it return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001–2003 time frames.

SCE has taken other remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance and disciplining employees who committed wrongdoing. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004. As with the customer satisfaction matter, the CPUC has not yet opened a formal investigation into this matter.

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 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 (SCs) in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from SCs 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 SC 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 February 7, 2006, the FERC advised SCE that the FERC will move the Court of Appeals for a voluntary remand so that the FERC may amend the order on appeal. A decision is expected in late 2006. The FERC may require SCE to pay these costs, but SCE does not believe this outcome is probable. If SCE is required to pay these costs, SCE may seek recovery in its reliability service rates.

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation 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, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss. The D.C. District Court denied these motions for dismissal, except for Salt River Project Agricultural Improvement and Power District's motion for its separate dismissal from the lawsuit.

Certain issues related to this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the United States Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's conclusion, SCE and Peabody brought motions to dismiss or for summary judgment in the D.C. District Court action but the D.C. District Court denied the motions on April 13, 2004.

The Court of Appeals for the Federal Circuit, acting on a suggestion filed by the Navajo Nation on remand from the Supreme Court's March 4, 2003 decision held in an October 24, 2003 decision that the Supreme Court's decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. On March 16, 2004, the Federal Circuit issued an order remanding the case against the Government to the Court of Federal Claims, which considered (1) whether the Navajo Nation previously waived its "network of other laws" argument and, (2) if not, whether the Navajo Nation can establish that the Government breached any fiduciary duties pursuant to such "network." On December 20, 2005, the Court of Federal Claims issued its ruling and found that although there was no waiver, the Navajo Nation did not establish that a "network of other laws" created a judicially enforceable trust obligation. The Navajo Nation filed a notice of appeal from this ruling on February 14, 2006.

Pursuant to a joint request of the parties, the D.C. District Court granted a stay of the action in that court to allow the parties to attempt to resolve, through facilitated negotiations, all issues associated with Mohave. Negotiations are ongoing and the stay has been continued until further order of the court.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact on the complaint of the Supreme Court's decision and the recent Court of Federal Claims ruling in the Navajo Nation's suit against the Government, or the impact of the complaint on the possibility of resumed operation of Mohave following the cessation of operation on December 31, 2005.

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 Nuclear Regulatory Commission 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 on August 31, 2008. Based on its ownership interests, SCE could be required to pay a maximum of $199 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 $44 million per year. Insurance premiums are charged to operating expense.

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, 2017. The Joint Energy Action Plan adopted in 2003 by the CPUC and the California Energy Commission (CEC) accelerated the deadline to 2010.

SCE entered into a contract with Calpine Energy Services, L.P. (Calpine) to purchase the output of certain existing geothermal facilities in northern California. In January 2003, the CPUC issued a resolution approving the contract. SCE interpreted the resolution as authorizing SCE to count all of the output of the geothermal facilities towards the obligation to increase SCE's procurement from renewable resources and counted the entire output of the facilities toward its 1% obligation in 2003, 2004 and 2005. On July 21, 2005, the CPUC issued a decision stating that SCE can only count procurement pursuant to the Calpine contract towards its 1% annual renewable procurement requirement if it is certified as "incremental" by the CEC. On February 1, 2006, the CEC certified approximately 25% and 17% of SCE's 2003 and 2004 procurement, respectively, from the Calpine geothermal facilities as "incremental." A similar outcome is anticipated with respect to the CEC's certification review for 2005.

On August 26, 2005, SCE filed an application for rehearing and a petition for modification of the CPUC's July 21, 2005 decision. On January 26, 2006, the CPUC denied SCE's application for rehearing of the decision. The CPUC has not yet ruled on SCE's petition for modification. The petition for modification seeks a clarification that SCE will not be subjected to penalties for relying on the CPUC's 2003 resolution in submitting compliance reports to the CPUC and planning its subsequent renewable procurement activities. The petition for modification also seeks an express finding that the decision will be applied prospectively only; *i.e.*, that no past procurement deficits will accrue for any prior period based on the decision.

If SCE is not successful in its attempt to modify the July 21, 2005 CPUC decision and can only count the output deemed "incremental" by the CEC, SCE could have deficits in meeting its renewable procurement obligations for 2003 and 2004. However, based on the CPUC's rules for compliance with renewable procurement targets, SCE believes that it will have until 2007 to make up these deficits before becoming subject to penalties for those years. The CEC's and the CPUC's treatment of the output from the geothermal facilities could also result in SCE being deemed to be out of compliance in 2005 and 2006. Under current CPUC decisions, potential penalties for SCE's failure to achieve its renewable procurement obligations for any year will be considered by the CPUC in SCE's annual compliance filing.

On December 20, 2005, Calpine and certain of its affiliates initiated Chapter 11 bankruptcy proceedings in the United States Bankruptcy Court for the Southern District of New York. As part of those proceedings, Calpine sought to reject its contract with SCE as of the petition filing date. On

January 27, 2006, after the matter had been withdrawn from the Bankruptcy Court's jurisdiction, the United States District Court for the Southern District of New York denied Calpine's motion to reject the contract and ruled that the FERC has exclusive jurisdiction to alter the terms of the contract with SCE. Calpine has appealed the District Court's ruling to the United States Court of Appeals for the Second Circuit. Calpine may also file a petition with the FERC seeking authorization to reject the contract. The CPUC may take the position that any authorized rejection of the contract would cause SCE to be out of compliance with its renewable procurement obligations during any period in which renewable electricity deliveries are reduced or eliminated as a result of the rejection.

Further, in December 2005, SCE made filings advising the CPUC that the need for transmission upgrades to interconnect new renewable projects and the time it will take under the current process to license and construct such transmission upgrades may prevent SCE from meeting its statutory renewables procurement obligations through 2010 and potentially beyond 2010 depending in part on the results of a pending solicitation for new renewable resources. SCE has requested that the CPUC take several actions in order to expedite the licensing process for transmission upgrades. The CPUC may take the position that SCE's failure to meet the 20% goal by 2010 due to transmission constraints would cause SCE to be out of compliance with its renewable procurement obligations.

Under the CPUC's current rules, the maximum penalty for failing to achieve renewables procurement targets is $25 million per year. SCE cannot predict with certainty whether it will be assessed penalties.

Schedule Coordinator Tariff Dispute

SCE serves as a schedule coordinator for Los Angeles Department of Water & Power (DWP) over the ISO-controlled grid. In late 2003, SCE began charging DWP under a tariff subject to refund for FERC-authorized charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges are billed to DWP under a FERC tariff that remains subject to dispute. DWP has paid the amounts billed under protest but requested 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 DWP have not been shown to be just and reasonable and thus made them subject to refund and further review at the FERC. As a result, SCE could be required to refund all or part of the amounts collected from DWP under the tariff. During the fourth quarter of 2005 SCE accrued a $25 million charge to earnings for the potential refunds, reflected in the consolidated statements of income caption "Purchased power". If the FERC ultimately rules that SCE may not collect the scheduling coordinator charges from DWP and requires the amounts collected to be refunded to DWP, SCE would attempt to recover the scheduling coordinator charges from all transmission grid customers through another regulatory mechanism. However, the availability of other recovery mechanisms is uncertain, and ultimate recovery of the scheduling coordinator charges cannot be assured.

Spent Nuclear Fuel

Under federal law, the United States Department of Energy (DOE) is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its 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 DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. The case is currently stayed until March 31, 2006, when SCE will seek to lift the stay and go forward with the litigation.

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 is stored. There is now sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE is planning to begin moving Unit 2 and 3 spent fuel into the independent spent fuel storage installation by early 2007.

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed a dry cask storage facility. Arizona Public Service, as operating agent, plans to continually load casks on a schedule to maintain full core off-load capability for all three units.

Note 10. Business Segments

SCE's reportable business segments include the rate-regulated electric utility segment and the VIE segment. The VIEs were consolidated as of March 31, 2004. The VIEs are gas-fired power plants that sell both electricity and steam. The VIE segment consists of non-rate-regulated entities. 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 under the heading "Variable Interest Entities" in Note 1.

SCE's business segment information including all line items with VIE activities is:

In millions	Electric Utility	VIEs	Eliminations	SCE
Balance Sheet Items as of December 31, 2005:				
Cash	$ 23	$ 120	$ —	$ 143
Accounts receivable–net	794	174	(119)	849
Inventory	202	18	—	220
Prepayments and other current assets	88	4	—	92
Nonutility property–net of depreciation	741	345	—	1,086
Other long-term assets	535	10	—	545
Total assets	**24,151**	**671**	**(119)**	**24,703**
Accounts payable	813	204	(119)	898
Other current liabilities	808	2	—	810
Long-term debt	4,615	54	—	4,669
Asset retirement obligations	2,608	13	—	2,621
Minority interest	—	398	—	398
Total liabilities and shareholder's equity	**24,151**	**671**	**(119)**	**24,703**
Balance Sheet Items as of December 31, 2004:				
Cash and equivalents	$ 32	$ 90	$ —	$ 122
Accounts receivable–net	569	153	(104)	618
Inventory	181	15	—	196
Prepayments and other current assets	43	3	—	46
Nonutility property–net of depreciation	583	377	—	960
Other long-term assets	562	5	—	567
Total assets	**22,751**	**643**	**(104)**	**23,290**
Accounts payable	638	166	(104)	700
Other current liabilities	641	2	—	643
Long-term debt	5,171	54	—	5,225
Customer advances and other deferred credits	498	12	—	510
Minority interest	—	409	—	409
Total liabilities and shareholder's equity	**22,751**	**643**	**(104)**	**23,290**

In millions	Electric Utility	VIEs	Eliminations*	SCE
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
Other operation and maintenance	2,421	102	—	2,523
Depreciation, decommissioning and amortization	878	37	—	915
Total operating expenses	7,743	1,063	(935)	7,871
Operating income	1,295	334	—	1,629
Minority interest	—	334	—	334
Net income	**749**	**—**	**—**	**749**
Income Statement Items for the Year-Ended December 31, 2004:				
Operating revenue	$ 8,163	$ 954	$ (669)	$ 8,448
Fuel	232	578	—	810
Purchased power	3,001	—	(669)	2,332
Other operation and maintenance	2,389	68	—	2,457
Depreciation, decommissioning and amortization	832	28	—	860
Total operating expenses	6,430	674	(669)	6,435
Operating income	1,733	280	—	2,013
Minority interest	—	280	—	280
Net income	**921**	**—**	**—**	**921**

* 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 11. Discontinued Operations

In July 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders. In accordance with an accounting standard related to the impairment and disposal of long-lived assets, this oil storage and pipeline facilities unit's results have been accounted for as a discontinued operation in the 2003 financial statements. For 2003, revenue from discontinued operations was $20 million and pre-tax income was $82 million.

Note 12. Acquisition

In March 2004, SCE acquired Mountainview Power Company LLC, which consisted of a power plant in early stages of construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project. The Mountainview project is fully operational.

Quarterly Financial Data (Unaudited) — Southern California Edison Company

In millions	**2005 Total**	**Fourth**	**Third**	**Second**	**First**	2004 Total	Fourth	Third	Second	First
Operating revenue	**$9,500**	**$2,306**	**$3,084**	**$2,203**	**$1,908**	$8,448	$1,920	$2,655	$2,176	$1,696
Operating income	**1,629**	**345**	**568**	**388**	**328**	2,013	499	682	587	245
Net income	**749**	**163**	**287**	**166**	**132**	921	317	260	243	101
Net income available for common stock	**725**	**153**	**280**	**161**	**131**	915	315	259	242	100
Common dividends declared	**285**	**71**	**143**	**71**	**—**	750	155	150	145	300

Totals may not add precisely due to rounding.

Selected Financial and Operating Data: 2001 – 2005			Southern California Edison Company		
Dollars in millions	**2005**	**2004**	**2003**	**2002**	**2001**
Income statement data:					
Operating revenue	**$ 9,500**	$ 8,448	$ 8,854	$ 8,706	$ 8,126
Operating expenses	**7,871**	6,435	7,276	6,588	3,509
Purchased-power expenses	**2,622**	2,332	2,786	2,016	3,770
Income tax	**292**	438	388	642	1,658
Provisions for regulatory adjustment clauses – net	**435**	(201)	1,138	1,502	(3,028)
Interest expense – net of amounts capitalized	**360**	409	457	584	785
Net income from continuing operations	**749**	921	882	1,247	2,408
Net income	**749**	921	932	1,247	2,408
Net income available for common stock	**725**	915	922	1,228	2,386
Ratio of earnings to fixed charges	**3.79**	4.40	3.81	4.21	6.15
Balance sheet data:					
Assets	**$ 24,703**	$ 23,290	$ 21,771	$ 36,058	$ 22,453
Gross utility plant	**19,232**	17,981	16,991	16,232	15,982
Accumulated provision for depreciation and decommissioning	**4,763**	4,506	4,386	4,057	7,969
Short-term debt	**—**	88	200	—	2,127
Common shareholder’s equity	**4,930**	4,521	4,355	4,384	3,146
Preferred and preference stock:					
Not subject to mandatory redemption	**729**	129	129	129	129
Subject to mandatory redemption	**—**	139	141	147	151
Long-term debt	**4,669**	5,225	4,121	4,525	4,739
Capital structure:					
Common shareholder’s equity	**47.7%**	45.1%	49.8%	47.7%	38.5%
Preferred stock:					
Not subject to mandatory redemption	**7.1%**	1.3%	1.5%	1.4%	1.6%
Subject to mandatory redemption	**—**	1.4%	1.6%	1.6%	1.9%
Long-term debt	**45.2%**	52.2%	47.1%	49.3%	58.0%
Operating data:					
Peak demand in megawatts (MW)	**21,934**	20,762	20,136	18,821	17,890
Generation capacity at peak (MW)	**10,536**	10,207	9,861	9,767	9,802
Kilowatt-hour deliveries (in millions)	**100,992**	97,273	92,763	79,693	78,524
Total energy requirement (kWh) (in millions)	**78,772**	78,738	77,158	71,663	83,495
Energy mix:					
Thermal	**37.0%**	33.7%	37.9%	40.2%	32.5%
Hydro	**6.5%**	4.5%	5.2%	5.0%	3.6%
Purchased power and other sources	**56.5%**	61.8%	56.9%	54.8%	63.9%
Customers (in millions)	**4.74**	4.67	4.60	4.53	4.47
Full-time employees	**14,041**	13,454	12,698	12,113	11,663

Board of Directors

John E. Bryson [3,6]
Chairman of the Board,
President and
Chief Executive Officer,
Edison International;
Chairman of the Board, Southern
California Edison Company;
Chairman of the Board, Edison Capital
A director from 1990-1999;
2003 to present

France A. Córdova [4,5]
Chancellor,
University of California, Riverside
Riverside, California
A director since 2004

Alan J. Fohrer [3,6]
Chief Executive Officer,
Southern California Edison Company
A director since 2002

Bradford M. Freeman [1,4,5]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Bruce Karatz [2,3,5]
Chairman and Chief Executive Officer,
KB Home (homebuilding)
Los Angeles, California
A director since 2002

Luis G. Nogales [1,2,4,7]
Managing Partner,
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

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

James M. Rosser [3,4]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1985

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

Robert H. Smith [1,2,5]
Robert H. Smith Investments
and Consulting
(banking and financial-related
consulting services)
Pasadena, California
A director since 1987

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

1 Audit Committee
2 Compensation and Executive Personnel Committee
3 Executive Committee
4 Finance Committee
5 Nominating/Corporate Governance Committee
6 Pricing Committee
7 Pricing Committee (Alternate Member)

Management Team

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

John R. Fielder
President

Bruce C. Foster
Senior Vice President,
Regulatory Operations

Polly L. Gault
Senior Vice President,
Public Affairs

Ronald L. Litzinger
Senior Vice President,
Transmission and Distribution

Thomas M. Noonan
Senior Vice President and
Chief Financial Officer

Stephen E. Pickett
Senior Vice President and
General Counsel

Pedro J. Pizarro
Senior Vice President,
Power Procurement

Richard M. Rosenblum
Senior Vice President,
Generation and Chief Nuclear Officer

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

Lynda L. Ziegler
Senior Vice President,
Customer Service

Robert C. Boada
Vice President and Treasurer

William L. Bryan
Vice President,
Business Customer Division

Ann P. Cohn
Vice President and
Associate General Counsel

Jodi M. Collins
Vice President,
Information Technology

Diane L. Featherstone
Vice President and General Auditor

Frederick J. Grigsby, Jr.
Vice President,
Human Resources and Labor Relations

Harry B. Hutchison
Vice President,
Customer Service Operations

Akbar Jazayeri
Vice President,
Revenue and Tariffs

Walter J. Johnston
Vice President,
Power Delivery

Brian Katz
Vice President,
Nuclear Oversight and
Regulatory Affairs

James A. Kelly
Vice President,
Engineering and Technical Services

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

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

Barbara J. Parsky
Vice President,
Corporate Communications

Kevin M. Payne
Vice President,
Enterprise Resource Planning

Frank J. Quevedo
Vice President,
Equal Opportunity

James T. Reilly
Vice President,
Nuclear Engineering and
Technical Services

Anthony L. Smith
Vice President,
Tax

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

Linda G. Sullivan
Vice President and
Controller

Raymond W. Waldo
Vice President,
Nuclear Generation

Shareholder Information

Annual Meeting

The annual meeting of shareholders will be held on Thursday, April 27, 2006, 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

Wells Fargo Shareowner Services℠
www.wellsfargo.com/shareownerservices

Web Address
www.edisoninvestor.com

Online account information:
www.shareowneronline.com

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