EDISON

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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 118-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. These statements are based on Southern California Edison's (SCE) knowledge of present facts, current expectations about future events and assumptions about future developments. Forward-looking statements are not guarantees of performance; they are subject to risks and uncertainties that could cause actual future outcomes and results of operations to be materially different from those set forth in this discussion. Important factors that could cause actual results to differ are discussed throughout this MD&A, including in the management overview and the discussions of liquidity and market risk exposures.

The MD&A is presented in 11 major sections. The MD&A begins with (1) a management overview, which includes a summary of the major objectives for 2003 and 2004, a brief review of the company's consolidated earnings for 2003, and a description of how SCE earns revenue and income. The remaining sections of the MD&A include: (2) Liquidity; (3) Market Risk Exposures; (4) Regulatory Matters; (5) Other Developments; (6) Results of Operations and Historical Cash Flow Analysis; (7) Disposition and Discontinued Operations; (8) Acquisition; (9) Critical Accounting Policies; (10) New Accounting Principles; and (11) Commitments.

MANAGEMENT OVERVIEW

Summary

SCE was significantly impacted by California's energy crisis from 2000 into 2002. In 2003, SCE's management focused on restoring the company's financial health, chiefly by accomplishing three crucial objectives:

- Validating and completing SCE's recovery of power procurement costs arising from the energy crisis. In July 2003, SCE completed recovery of $3.6 billion of procurement-related obligations through the regulatory account known as the Procurement-Related Obligations Account (PROACT). By late 2003, both the California Supreme Court and the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) had issued decisions upholding the 2001 settlement agreement with the California Public Utilities Commission (CPUC) that provided for creation of the PROACT and SCE's recovery of procurement-related costs. (See "Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," and "—PROACT Regulatory Asset.")

- Rebalancing SCE's capital structure to levels authorized by the CPUC. (See "Liquidity.") This was largely accomplished by a dividend to Edison International in December 2004 and financing activities in early 2004.

- Achieving an investment grade credit rating. In the fourth quarter of 2003, Moody's Investors Service and Standard & Poor's both raised SCE's credit ratings to investment grade. (See "Liquidity.")

In addition to SCE's ongoing emphasis on operational excellence, including system reliability, safety, customer satisfaction and employee development, during 2004 SCE's management will seek to further strengthen the company's financial and regulatory position by focusing on the following key objectives:

- Achieving sound regulatory outcomes, including a fair and durable regulatory framework, rate stability, and full recovery of energy procurement costs.

- Developing new resources, such as the proposed Mountainview plant, and investing in other major capital projects when customer and shareholder value are enhanced.

These objectives are discussed below in "—Issues Overview" and succeeding sections of this MD&A.

SCE recorded earnings of $922 million in 2003, compared to $1.2 billion in 2002, which included a gain of $480 million related to a regulatory decision on utility-retained generation (URG). Excluding this one-time gain 2002 gain, SCE's earnings increased $174 million over 2002. Major factors contributing to the increase over the prior year included the resolution of significant regulatory proceedings and a $44 million gain on the sale of SCE's fuel oil pipeline business. For a detailed review and analysis of the consolidated results of operations and historical cash flow analysis, see "Results of Operations and Historical Cash Flow Analysis" section.

Background

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 two groups: base rates and cost-recovery 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 the net book value of SCE's investment in generation and distribution plant (or rate base). Base rates provide for recovery of operations and maintenance (O&M) 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 currently authorized by the CPUC through a General Rate Case (GRC) proceeding. 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 O&M 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 O&M costs, changes in capital-related costs and the expected number of nuclear refueling outages. 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 costs, other than cost-recovery costs (see below), do impact profitability.

SCE's capital structure, including the authorized rate of return, is regulated by the CPUC and is determined in annual cost of capital proceedings. The rate of return is a blend of a return on equity and cost of long-term debt and preferred stock. SCE's 2003 cost of capital decision, issued on November 7, 2002, will remain in effect throughout 2004. Accordingly, SCE's CPUC-authorized rate of return of 9.75%, return on common equity of 11.6% and authorized rate-making capital structure will be maintained through 2004.

Current CPUC ratemaking also provides for performance incentives or penalties for differences between actual results and GRC-determined standards of reliability, customer satisfaction and employee safety.

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 is subject to refund until a FERC decision is issued. SCE currently receives approximately $260 million in annual revenue to recover the costs associated with its transmission function and to earn a reasonable return on its $1.1 billion transmission rate base.

Cost-Recovery Rates: Revenue requirements to recover SCE's costs of fuel, power procurement, demand-side management programs, nuclear decommissioning costs, and rate reduction debt requirements are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 50% 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 in these categories in future proceedings, under- or over-collections in these balancing accounts can build rapidly due to fluctuating prices (particularly in power procurement) and can greatly impact cash flows. 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.

As described below under "Regulatory Matters—Generation and Power Procurement—CDWR Power Purchases and Revenue Requirement Proceedings," the California Department of Water Resources (CDWR) began purchasing power on behalf of utility customers during the California energy crisis. In addition to billing its customers for SCE's power procurement activities, SCE also bills and collects from its customers for power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. These amounts are remitted to the CDWR as they are collected and are not recognized as revenue by SCE. As a result, these transactions should have no impact on SCE's earnings or cash flow.

For a discussion of important issues related to the rate-making process, see the "Regulatory Matters" section.

Issues Overview

This overview discusses key business issues facing SCE. It is not intended to be an exhaustive discussion. It includes issues that could materially affect SCE's earnings, cash flow or business risk. The overview includes a discussion of current and planned capital expenditures (including the acquisition and construction of the Mountainview project, either potential expenditures or the possibility of a shutdown at the Mohave Generating Station (Mohave), and costs of replacing the steam generators at the San Onofre Nuclear Generating Station (San Onofre)), anticipated procurement requirements (including the effects of a resource adequacy requirement, community aggregation, and related ratemaking), and the 2003 and 2006 CPUC General Rate Cases.

The issues discussed in this overview are described in more detail in the remainder of this MD&A.

SCE's utility business is experiencing significant growth in actual and planned capital expenditures. SCE plans to spend up to $1.9 billion during 2004, compared to $1.2 billion in 2003. The growth in spending will require a partial reinvestment of earnings and issuance of debt securities to maintain a balanced capital structure, as required by the CPUC. For 2005 and beyond, capital spending is anticipated to remain at levels substantially above historical levels, but somewhat below planned spending for 2004.

Each of SCE's business areas (distribution, transmission and generation) is contributing to the capital spending growth. The distribution area, which represents approximately 70% of SCE's rate base, is experiencing continued expansion of the number of customer accounts. Beginning with a base of

4.6 million active accounts, for 2004, SCE expects to add approximately 60,000 new accounts, and forecasts a similar level of activity over the next several years. SCE also forecasts that it will need to accelerate the replacement of distribution poles, transformers and other infrastructure to maintain existing levels of system reliability.

SCE forecasts that expenditures for transmission facilities will substantially increase over the balance of the decade. SCE is now planning for and beginning to construct new substations to meet customer load-growth requirements. Moreover, SCE is conducting preliminary engineering on new and existing transmission lines that would expand the capacity to bring in additional energy from the Southwest.

In 2004, generation capital expenditures will increase dramatically, driven primarily by the recently approved Mountainview project. In addition, SCE will spend in excess of $50 million at the San Onofre plant to construct facilities to protect the site against a design basis threat as determined by the Nuclear Regulatory Commission. These expenditures are in addition to ongoing capital expenditures to maintain the safety and reliability of SCE's nuclear, coal and hydroelectric facilities. Beyond 2004, SCE may replace the San Onofre steam generators in the 2009–2010 time frame. Given the lead-time requirements to fabricate the steam generators, SCE must make commitments to begin fabrication during 2004.

Recently, the CPUC ordered all load-serving entities to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. This resource adequacy requirement, combined with the anticipated closure of Mohave at the end of 2005, expected reductions in deliveries under CDWR contracts, expected expiration of contracts with some independent power producers known as qualifying facilities (QFs), and expected peak-load growth of 1.5–2.0% per year, will require SCE to either construct new generation facilities or enter into additional power-purchase contracts to provide for forecasted customer requirements. Implementation of the CPUC order will be addressed in workshops commencing in mid-March 2004.

At the same time that SCE is evaluating new generation investments and contractual obligations, SCE has raised fundamental concerns about the stability of its customer base in the CPUC's ongoing long-term procurement proceeding. The CPUC's direct access rules, the possible expansion of community choice aggregation, other forms of municipalization, and application of exit fees to departing customers all affect the ability of SCE to retain bundled service customers (customers who purchase power from SCE). It is SCE's goal to ensure that customers who depart from utility generation service pay their fair share of costs, and that costs are not unfairly shifted to remaining bundled service customers, which could have the effect of increasing SCE's rates and causing more customers to seek alternative providers.

SCE is aware that the concern for high rates was a contributing factor that led California regulators to deregulate the electric services industry in the mid-1990's. Today, SCE's system average rate is 12.3¢-per-kilowatt-hour (kWh) for bundled service customers and its average monthly bill is $79. On a cents-per-kWh basis, SCE's average rate is above the national average, but similar to the other investor-owned electric utilities in California. Therefore, SCE is focused on providing bundled service customers competitive and stable electric rates. But this focus must be balanced with the obligation to safely and reliably serve customers.

At the beginning of 2003, SCE resumed procurement of power for its bundled service customers. During 2003, much of management's attention was focused on establishing fair and reasonable rules for the procurement of power for utility customers. Additional work is needed. For 2004 and 2005, SCE forecasts that it will have a residual long position in the majority of hours. SCE's residual-net long position arises primarily because of the CPUC's allocation of CDWR contract energy. For the reasons listed above, such as customer growth and run-off of existing contracts, SCE expects to have substantially greater power procurement requirements beyond 2005. The acquisition and construction of the Mountainview project, the replacement of the San Onofre steam generators and the expansion of transmission facilities are all part of SCE's plan to meet a portion of expected customer requirements. However, even more additional resources will be needed to meet those expected requirements.

To promote and ensure recovery of both generation investments and contract costs, SCE has established a corporate priority to secure a fair and durable regulatory framework. To this end, SCE supports adoption of Assembly Bill 2006, introduced by California's Speaker of the Assembly Fabian Nunez. The bill is pending before the California State Assembly.

SCE is in the final stages of its 2003 GRC proceeding, which will set annual base rates for the years 2003–2005 years. On February 13, 2004, SCE received a proposed decision from the administrative law judge that heard the 2003 GRC. SCE is seeking a $251 million increase in its annual base rate revenue, but the proposed decision would allow only a $15 million increase. SCE is disappointed with the proposed decision and will press for reinstatement of its requested amount by the CPUC commissioners. The CPUC commissioners can accept, reject, or modify any proposed decision.

SCE is now preparing its 2006 General Rate Case. SCE's preliminary application files in August 2004, with the application scheduled to file before year-end 2004. With the expected growth in capital spending discussed above, SCE expects that it will need further increases in its revenue requirement.

LIQUIDITY

SCE's liquidity is primarily affected by under- or over-collections of procurement-related costs as discussed in "Management Overview—Background" and access to capital markets or external financings. In the fourth quarter of 2003, Moody's Investors Service and Standard & Poor's both raised SCE's credit ratings to investment grade.

At December 31, 2003, SCE had cash and equivalents of $95 million. SCE's long-term debt, including current maturities, at December 31, 2003, was $4.5 billion. SCE has a $700 million credit facility that expires in December 2006. SCE drew $200 million on the facility on December 19, 2003. In addition, the facility supported letters of credit in the amount of $33 million at year-end 2003. At December 31, 2003, SCE had borrowing capacity under its credit facility of $467 million. SCE's 2004 cash requirements consist of:

- $125 million of 5.875% bonds due in September 2004;
- Approximately $246 million of rate reduction notes that are due at various times in 2004, but which have a separate cost recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures of $1.9 billion, including the investment in the Mountainview project and related capital expenditures (see "Acquisition");
- Dividend payments to SCE's parent company;
- Fuel and procurement-related costs; and
- General operating expenses.

SCE expects to meet its continuing obligations and cash outflows for 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 cash flows and the issuance of long-term debt.

SCE's capital structure is regulated by the CPUC. SCE's CPUC-authorized common equity to total capitalization ratio level is 48%. On October 16, 2003, SCE transferred, through a dividend to Edison International, $945 million of equity that exceeded the CPUC-authorized level. This dividend was a first step to rebalance SCE's capital structure in accordance with CPUC requirements. As of December 31, 2003, SCE's common equity to total capitalization ratio, for rate-making purposes, was approximately 55%.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $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. The proceeds were used to redeem $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 March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

SCE resumed procurement of its residual-net short (the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power-purchase contracts and CDWR contracts) on January 1, 2003, and as of December 31, 2003, had posted approximately $66 million ($33 million in cash and $33 million in letters of credit) as collateral to secure its obligations under power-purchase contracts and to transact through the Independent System Operator (ISO) for imbalance energy. SCE's collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, the ISO's credit requirements, changes in market prices relative to contractual commitments, and other factors.

SCE's liquidity may be affected by, among other things, matters described in "Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," "—CDWR Power Purchases and Revenue Requirement Proceedings," and "—Generation Procurement Proceedings" sections.

MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, generating fuel commodity prices and volume and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. However, fluctuations in fuel prices and volumes and counterparty credit losses temporarily affect cash flows, but should not affect earnings.

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 and to fund business operations, as well as 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 (11.6% for 2003 and 2004), 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, 2003, SCE did not believe that its short-term debt and current portion of long-term debt and preferred stock was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value.

At December 31, 2003, the fair market value of SCE's long-term debt was $4.4 billion. A 10% increase in market interest rates would have resulted in a $166 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 $183 million increase in the fair market value of SCE's long-term debt. At December 31, 2003, the fair market value of SCE's preferred stock subject to mandatory redemption was $139 million. A 10% increase in market interest rates would have resulted in a $12 million decrease in the fair market value of SCE's preferred stock subject to mandatory redemption. A 10% decrease in market interest rates would have resulted in a $14 million increase in the fair market value of SCE's preferred stock subject to mandatory redemption.

Generating Fuel Commodity Price Risk

SCE's purchased-power expense in 2003 was approximately 38% of SCE's total operating expenses. SCE recovers its reasonable power procurement costs through regulatory mechanisms established by the CPUC. The California public utilities code provides that the CPUC shall adjust rates, or order refunds, to amortize undercollections or overcollections of power procurement costs. Until January 1, 2006, the CPUC must adjust rates if the undercollection or overcollection exceeds 5% of SCE's prior year's procurement costs, excluding revenue collected for the CDWR. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but should have no impact on earnings.

On January 1, 2003, SCE resumed procurement of its residual-net short. SCE forecasts that it will have a residual long position in the majority of hours for 2004. SCE's residual-net long position arises from an expected increase in deliveries under CDWR contracts allocated to SCE's customers. SCE has incorporated a price and volume forecast from expected sales of residual-net long power in its 2004 procurement plan filed with the CPUC, as well as in the revenue forecast used for setting rates. If actual prices or volumes vary from forecast, SCE's cash flow would be temporarily impacted, but should not affect earnings. For 2004 and beyond, several factors could cause SCE's residual-net short to be much larger than expected, including the return of direct access customers (customers who choose to purchase power directly from an electric service provider other than SCE) to utility service, lower utility generation due to expected or unexpected outages or plant closures, lower deliveries under third-party power contracts, higher than anticipated demand for electricity, or displacement of existing generation resources with economic short-term transactions. Such an increase in procurement requirements could lead to temporary revenue undercollections if the costs to purchase the additional energy were to exceed the amount recovered in rates.

SCE anticipates it will need to purchase additional capacity and/or ancillary services to meet its peak-energy requirements in 2004 and 2005. In 2006, SCE's residual-net short exposure will increase significantly from the reduction in expected CDWR power deliveries, expiration of certain contracts with QFs, expected shutdown of Mohave, and load growth.

Pursuant to CPUC decisions, SCE, as the CDWR's limited agent, arranges for natural gas and performs related services for CDWR contracts allocated to SCE by the CPUC. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through the coordination of SCE, has hedged a portion of its expected natural gas requirements for certain contracts allocated to SCE. To the extent the price of natural gas were to increase above the levels assumed for cost recovery purposes, California state law permits the CDWR to recover its actual costs through rates established by the CPUC. This would affect rates charged to SCE's customers, but would not affect SCE's earnings or cash flows.

SCE purchases power from QFs under CPUC state-mandated contracts. Contract energy prices for most nonrenewable QFs are tied to the Southern California border price of natural gas established on a monthly basis. The CPUC has authorized SCE to hedge a majority of its natural gas price exposure associated with these QF contracts. During 2003, SCE substantially hedged the risk of increasing natural gas prices through hedging instruments purchased in late 2001 pursuant to authority granted by the CPUC. The cost of these hedging instruments was recovered through PROACT. None of these hedging instruments were outstanding as of December 31, 2003. The CPUC approved SCE's short-term resource plan, which includes hedging of natural gas price exposure for its existing QF contracts for 2004. These hedging costs are recovered through a balancing account known as Energy Resource Recovery Account (ERRA) and should have no impact on earnings. 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.

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. 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 should not affect earnings.

REGULATORY MATTERS

This section of the MD&A describes SCE's regulatory matters in three main subsections:

- generation and power procurement;
- transmission and distribution; and
- other regulatory matters.

Generation and Power Procurement

CPUC Litigation Settlement Agreement

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the Ninth Circuit seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

PROACT Regulatory Asset

In accordance with the 2001 CPUC settlement agreement described above and an implementing resolution adopted by the CPUC, in the fourth quarter of 2001, SCE established the PROACT regulatory balancing account, with an initial balance of approximately $3.6 billion. The initial balance reflected the net amount of past procurement-related liabilities to be recovered by SCE. On a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE was authorized by the CPUC to recover in retail electric rates was applied to the PROACT until SCE fully recovered the balance.

At July 31, 2003, the PROACT regulatory balancing account was overcollected by $148 million. On October 14, 2003, the CPUC approved SCE's advice filing which allowed SCE to transfer this July 31, 2003 overcollected PROACT balance and a temporary surcharge balancing account overcollection (see "—Generation and Power Procurement—Temporary Surcharges") to the ERRA (discussed below) on August 1, 2003, and to implement a $1.2 billion customer rate reduction effective August 1, 2003.

Energy Resource Recovery Account Proceedings

In an October 24, 2002 decision, the CPUC established the ERRA as the rate-making 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) new 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 in "Management Overview," 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. As these costs are subsequently incurred, they will be tracked and recovered 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 procurement costs, SCE can request an emergency rate adjustment in addition to the annual forecast and reasonableness ERRA applications.

SCE submitted its first ERRA forecast application in April 2003, in which it forecast procurement-related costs for the 2003 calendar year of $2.5 billion. On January 22, 2004, the CPUC issued a decision that approved SCE's forecast as submitted. The CPUC issued a proposed decision on February 24, 2004, approving SCE's 2004 forecast revenue requirement and rates for both generation and delivery services.

In October 2003, SCE submitted its first ERRA reasonableness review application, in which it requested the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. Because this is the first annual review of this activity, pursuant to new California state law, the CPUC's interpretation and application of California state law is uncertain. SCE cannot predict with certainty the outcome of its application and recovery of its procurement-related operations costs.

Pursuant to the assigned commissioner's scoping memo issued on December 9, 2003, the CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA testimony, due on March 19, 2004, will include an audit of these accounting calculations. Hearings are scheduled to be held during April 2004.

Utility-Retained Generation

As a result of an April 2002 CPUC decision, SCE's retained generation assets were returned to cost-of-service ratemaking after operating in a deregulated environment since 1998. The CPUC decision provided for the: (1) recovery of costs for all URG components other than San Onofre Units 2 and 3, subject to reasonableness review by the CPUC; (2) retention of the incremental cost incentive pricing mechanism (ICIP) for San Onofre Units 2 and 3 through 2003; (3) establishment of an amortization schedule for SCE's nuclear facilities that reflects their current remaining Nuclear Regulatory Commission license durations, using unamortized balances as of January 1, 2001 as a starting point; (4) establishment of balancing accounts for the costs of utility generation, purchased power, and ancillary services purchased from the ISO; and (5) continuation of the use of SCE's last CPUC-authorized return on common equity of 11.6% for SCE's URG rate base other than San Onofre Units 2 and 3, and the 7.35% return on rate base for San Onofre Units 2 and 3 under the ICIP. SCE will operate under the April 2002 CPUC decision until implementation of the 2003 GRC (see "—Transmission and Distribution—2003 General Rate Case Proceeding").

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity purchases. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its electricity 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). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

Direct Access Proceedings

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an electric service provider other than SCE (thus becoming direct access customers) or continue to purchase power from SCE. During that time, direct access customers received a credit for the generation costs SCE saved by not serving them, resulting in additional undercollected power procurement costs to SCE during 2000 and 2001. On March 21, 2002, the CPUC issued a decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001 are invalid. That decision did not affect direct access arrangements in place before that date.

In May 2003, a CPUC decision allowed customers with valid direct access arrangements to switch back and forth between bundled service provided by SCE and direct access. This decision, as well as CPUC decisions or proceedings discussed below, affects SCE's ability to predict the size of its customer base, the amount of bundled service load for which it must procure or generate electricity, its net-short position and its ability to plan for resource requirements.

The CPUC has received several petitions requesting clarification of previous decisions on whether to allow load growth on existing direct access accounts or add new accounts if necessary to accommodate direct access customers who relocate their facilities. Recently, the CPUC agreed, in response to one of these petitions, to allow direct access customers to add new accounts when relocating facilities as long as there is no increase in a customer's total eligible direct access load. SCE cannot predict how the CPUC will rule on the remaining petitions. If the CPUC allows load growth on existing direct access accounts and allows new direct access accounts to be added notwithstanding the suspension of direct access, the level of direct access load in SCE's territory could rise considerably, resulting in a shift of a greater portion of SCE's costs to bundled service customers.

The CPUC has also opened a proceeding to identify issues relating to the implementation of a 2002 California law authorizing community choice aggregation. This form of direct access allows local governments to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers program and to create an entity called a community choice aggregator. Hearings on this matter are scheduled to begin in May 2004. Depending on how many, if any, cities choose to participate in community choice aggregation, a large amount of load could depart from SCE's bundled service, resulting in additional shifting of cost responsibility.

The CPUC has issued decisions or has opened proceedings to establish various charges (exit fees) for customers who (1) switch to another electric service provider, (2) switch to a municipal utility; or (3) install onsite generation facilities or arrange to purchase power from another entity that installs such facilities. The charges recovered from these customers are used to reduce SCE's rates to bundled service customers and have no impact on earnings.

Temporary Surcharges

A March 2001 CPUC decision, authorized a 3¢-per-kWh revenue surcharge to SCE's customers and made permanent a 1¢-per-kWh surcharge to SCE's customers authorized in January 2001. In addition, the CPUC authorized an additional 0.6¢-per-kWh catch-up surcharge for a twelve-month period, beginning in June 2001, to compensate SCE for a delay in collecting the 3¢-per-kWh surcharge. These surcharges were used for SCE's procurement costs.

The CPUC later allowed the continuation of the 0.6¢-per-kWh catch-up surcharge. Amounts collected between June 2002 and December 2002 were to be used to recover 2003 procurement costs. As a result, at December 31, 2002, this revenue ($187 million of surcharge revenue) was credited to a regulatory liability account until it was used to offset SCE's higher 2003 procurement revenue requirement. Between January 1, 2003 and July 31, 2003, $150 million of this regulatory liability account was amortized into revenue. The remaining balance of $37 million was transferred to the ERRA as of August 1, 2003.

The $1.2 billion customer rate reduction plan implemented by SCE eliminated all of the temporary surcharges (see "—Generation and Power Procurement—PROACT Regulatory Asset").

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 procurement plan for SCE, which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002 CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with CDWR contracts is included within the cap.

Mohave Generating Station and Related Proceedings

On May 17, 2002, SCE filed an application with the CPUC to address certain issues (mainly coal and slurry-water supply issues) facing the future extended operation of Mohave, which is partly owned by SCE. Mohave obtains 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 is 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.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The 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 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 are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes, and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

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

In light of all of the issues discussed above, SCE has concluded that it is probable Mohave will 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 cost was deferred and recorded as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through a balancing account mechanism presented in its May 17, 2002 application and discussed in its supplemental testimony filed in January 2003.

Transmission and Distribution

2003 General Rate Case Proceeding

On May 3, 2002, SCE filed its application for a 2003 GRC, requesting: (1) a 2003 revenue requirement of approximately $3.1 billion; (2) a 2004 revenue requirement of approximately $3.5 billion; and (3) a 2005 revenue requirement of approximately $3.7 billion. These revenue requirements were based on SCE's projected rate base amounts of $7.8 billion in 2003, $8.2 billion in 2004 and $8.5 billion in 2005. When compared to forecast revenue at currently authorized rates (approximately $2.8 billion), SCE's 2003 GRC request was an increase of $286 million, which was subsequently revised to an increase of $251 million. The requested revenue increase for 2003 was primarily related to capital additions, updated depreciation costs and projected increases in pension and benefit expenses. The application also proposed an estimated base rate revenue decrease of $78 million in 2004, and a subsequent increase of $116 million in 2005. The forecast reduction in 2004 was largely attributable to the expiration of the San Onofre ICIP rate-making mechanism at year-end 2003 and a forecast of increased sales. The expiration of San Onofre ICIP mechanism is expected to decrease SCE's 2004 earnings by approximately $100 million. Beginning in 2004, San Onofre Units 2 and 3 cost recovery reverts to cost-of-service ratemaking.

In a proposed decision issued on February 13, 2004, a CPUC administrative law judge recommended that the CPUC adopt only $15 million of the $251 million increase in authorized base rate revenue requirement that SCE had requested. SCE filed comments opposing parts of the proposed decision in an attempt to restore important components of the requested revenue requirement. The CPUC is scheduled to vote on the proposed decision on March 16, 2004, either modifying or accepting it. If an alternate decision is proposed, a final decision could be delayed into April 2004. If the CPUC adopts the administrative law judge's proposed decision without modification, and if SCE does not reduce its expected capital or operating expenditures accordingly, SCE estimates that on an annual basis SCE's earnings per share would be about 15¢-per-share lower and cash flow would be approximately $135 million lower than if SCE's base rate request had been granted in full. SCE cannot predict with certainty the final outcome of SCE's GRC application.

Because processing of the GRC took longer than initially scheduled, in May 2003 the CPUC approved SCE's request to establish a memorandum account to track the revenue requirement increase during the period between May 22, 2003 (the date a final CPUC decision was originally scheduled to be issued) and the date a final decision is ultimately adopted. The revenue requirement approved in the final GRC decision will be effective retroactive to May 22, 2003. Any balance in the GRC memorandum account authorized by the CPUC would be recovered in rates beginning in 2004, together with the combined revenue requirement authorized by the CPUC in the GRC decision for 2003 and 2004.

Hearings to address revenue allocation and rate design issues have been continued until after the CPUC issues a decision on SCE's revenue requirement. Due to the implementation of SCE's $1.2 billion customer rate-reduction plan, rate design changes will not be effective until August 2004, at the earliest. Until SCE's 2003 GRC is implemented, SCE's revenue requirement related to distribution operations is determined through a performance-based rate-making (PBR) mechanism.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Transmission Rate Case

In July 2000, the FERC issued a decision in SCE's 1998 transmission rate case in which it ordered a reduction of approximately $38 million to SCE's requested annual transmission revenue requirement of $213 million. In the decision, the FERC rejected SCE's proposed method for allocating overhead costs between transmission and distribution operations, which accounted for approximately $24 million of the $38 million reduction. After the FERC decision, SCE sought recovery in distribution rates from the CPUC. In third quarter 2003, the CPUC authorized recovery of $133 million of overhead costs for the period April 1, 1998 to August 31, 2002, and SCE credited this amount to provisions for regulatory adjustment clauses – net in the consolidated statements of income. On September 22, 2003, the ORA applied for rehearing of the matter. On February 11, 2004, the CPUC denied the ORA's request and reaffirmed its decision authorizing recovery.

Wholesale Electricity and Natural Gas Markets

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)/ 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. Under the 2001 CPUC settlement agreement, mentioned in "—Generation and Power Procurement—CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below:

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso Natural Gas Company had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its ERRA mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

Other Regulatory Matters

Catastrophic Event Memorandum Account

The catastrophic event memorandum account (CEMA) is a CPUC-authorized mechanism that allows SCE to immediately start the tracking of all of its incremental costs associated with declared disasters or emergencies and to subsequently receive rate recovery of its reasonably incurred costs upon CPUC approval. Incremental costs associated with restoring utility service; repairing, replacing or restoring damaged utility facilities; and complying with governmental agency orders are tracked in the CEMA. SCE currently has a CEMA for the bark beetle emergency and initiated a second CEMA associated with the fires that occurred in SCE territory in October 2003. Costs tracked through the CEMA mechanism are expected to be recovered in future rates with no impact on earnings. However, cash flow will be impacted due to the timing difference between expenditures and rate recovery.

Bark Beetle CEMA

On March 7, 2003, the Governor of California issued a proclamation declaring a state of emergency in Riverside, San Bernardino and San Diego counties where an infestation of bark beetles has created the potential for catastrophic forest fires. The proclamation requested that the CPUC direct utilities with transmission lines in these three counties to ensure that all dead, dying and diseased trees and vegetation are completely cleared from their utility rights-of-way to mitigate the potential fire damage. SCE estimates that it may incur several hundred million dollars in incremental expenses over the next several years to remove over 350,000 of these trees. This cost estimate is subject to significant change, depending on a number of evolving circumstances, including, but not limited to the spread of the bark beetle infestation, the speed at which trees can be removed, and tree disposal costs. In 2003, SCE removed approximately 26,000 dead or dying trees at an incremental expense of approximately $18 million which has been reflected in the CEMA as of December 31, 2003. SCE expects to submit an advice filing with the CPUC in the first quarter of 2004 to recover these costs. SCE estimates that it will spend up to $150 million on this project in 2004.

Fire-Related CEMA

During the last two weeks of October 2003, wildfires damaged SCE's electrical infrastructure, primarily in the San Bernardino Mountains of Southern California where an estimated 1,500 power poles and 220 transformers were damaged or downed. SCE notified the CPUC that it initiated a CEMA on October 21, 2003 to track the incremental costs to repair and restore its infrastructure. These costs are estimated to be approximately $30 million. The balance in this CEMA account is approximately $9 million as of December 31, 2003.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

On January 9, 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. On November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but did not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Investigation 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 reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

OTHER DEVELOPMENTS

Electric and Magnetic Fields

Electric and magnetic fields naturally result from the generation, transmission, distribution and use of electricity. Since the 1970s, concerns have been raised about the potential health effects of electric and magnetic fields. After 30 years of research, a health hazard has not been established to exist. Potentially important public health questions remain about whether there is a link between electric and magnetic fields exposures in homes or work and some diseases, and because of these questions, some health authorities have identified electric and magnetic fields exposures as a possible human carcinogen.

In October 2002, the California Department of Health Services released to the CPUC and the public its report evaluating the possible risks from electric and magnetic fields. The conclusions in the report of the California Department of Health Services contrast with other recent reports by authoritative health agencies in that the California Department of Health Services has assigned a substantially higher probability to the possibility that there is a causal connection between electric and magnetic fields exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

It is not yet clear what actions the CPUC will take to respond to the report of the California Department of Health Services and to the recent electric and magnetic fields reports by other health authorities such as the National Institute of Environmental Health Sciences, the World Health Organization's International Agency for Research on Cancer, and the United Kingdom's National Radiation Protection Board. Possible outcomes may include continuation of current policies or imposition of more stringent policies to implement greater reductions in electric and magnetic fields exposures. The costs of these different outcomes are unknown at this time.

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by the Internal Revenue Service in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for SCE's cash balance pension plan does not meet the standard set forth in the federal district court's July 31, 2003 decision. SCE cannot predict with certainty the effect of the two IBM decisions on SCE's cash balance pension plan.

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.

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 26 identified sites is $92 million. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in SCE's recorded estimated minimum environmental liability. 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 $238 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $34 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $71 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 $13 million to $25 million. Recorded costs for 2003 were $14 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.

Clean Air Act

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later).

In 1999, SCE and other co-owners of Mohave entered into a consent decree to resolve a federal court lawsuit that had been filed alleging violations of various emissions limits. This decree, approved by a federal court in December 1999, required certain modifications to the plant in order for it to continue to operate beyond 2005 to comply with the Clean Air Act.

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of Mohave beyond 2005 is estimated to be approximately $605 million. SCE has received from the State of Nevada a permit to install the necessary pollution-control equipment. However, SCE has suspended its efforts to seek CPUC approval to install the Mohave pollution-control equipment because it has not obtained reasonable assurance of adequate coal and water supplies for operating Mohave beyond 2005. Unless adequate coal and water supplies are obtained, it will become necessary to shut down Mohave after December 31, 2005. If the station is shut down at that time, the shutdown is not expected to have a material adverse impact on SCE's financial position or results of operations, assuming the remaining book value of the station (approximately $24 million as of December 31, 2003) and the related regulatory asset (approximately $66 million as of December 31, 2003), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict with certainty what effect any future actions by the CPUC may have on this matter. See "Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings" for further discussion of the Mohave issues.

SCE's facilities are subject to the Clean Air Act's new source review (NSR) requirements related to modifications of air emissions sources at electric generating stations. Over the past five years, the United States Environmental Protection Agency (EPA) has initiated investigations of numerous electric utilities seeking to determine whether these utilities engaged in activities in violation of the NSR requirements, brought enforcement actions against some of those utilities, and reached settlements with some of those utilities. EPA has made information requests concerning SCE's Four Corners station. Other than this request for information, no enforcement-related proceedings have been initiated against any SCE facilities by EPA relating to NSR compliance.

Over this same period, EPA has proposed several regulatory changes to NSR requirements that would clarify and provide greater guidance to the utility industry as to what activities can be undertaken without triggering the NSR requirements. Several of these regulatory changes have been challenged in the courts. As a result of these developments, EPA's enforcement policy on alleged NSR violations is currently uncertain.

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.

SCE's projected environmental capital expenditures are $2.3 billion, including the $605 million for Mohave discussed above for the 2004–2008 period, mainly for undergrounding certain transmission and distribution lines.

Federal Income Taxes

In August 2002, Edison International received a notice from the Internal Revenue Service asserting deficiencies in federal corporate income taxes for its 1994 to 1996 tax years. Included in these amounts are deficiencies asserted against SCE. Substantially all of SCE's tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would benefit SCE as future tax deductions. SCE believes that it has meritorious legal defenses to those deficiencies and believes that the ultimate outcome of this matter will not result in a material impact on SCE's consolidated results of operations or financial position.

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. 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.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the 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 analysis, on April 28, 2003, SCE filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 2003 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. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 Court of Appeals decision. Both petitions were denied on March 9, 2004.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

San Onofre Steam Generators

Like other nuclear power plants with steam generators of the same design and material properties, San Onofre Units 2 and 3 have experienced degradation in their steam generators. Based on industry experience and analysis of recent inspection data, SCE has determined that the existing San Onofre Unit 2 and 3 steam generators may not enable continued reliable operation of the units beyond their scheduled refueling outages in 2009–2010. SCE currently estimates that the cost of replacing the steam generators would be about $680 million, of which SCE's 75% share would be about $510 million. On February 27, 2004, SCE asked the CPUC to issue a decision by July 2005 finding that it is reasonable for SCE to replace the San Onofre Unit 2 and 3 steam generators and establishing appropriate ratemaking for the replacement costs. In its application, SCE stated that the San Onofre operating agreement requires unanimous approval of all co-owners for the costs of the steam generator replacement to be included in the capital budget for Units 2 and 3 and, therefore, SCE must have the approval of its co-owners to go forward as planned, which approval currently is lacking. Because SCE will need to enter into commitments in 2004 to obtain timely delivery of replacement steam generators, SCE also asked the CPUC to create a memorandum account by September 2004 for SCE to recover initial costs of up to $50 million if the replacement project ultimately is not approved by the CPUC or co-owner approval is not obtained. If the CPUC finds investment in the steam generators to be reasonable and cost effective and the steam generator replacement takes place, SCE's investment should be reflected in retail rates for recovery over the remaining useful life of the plants. SCE currently does not expect that it would proceed with replacement of the San Onofre Units 2 and 3 steam generators without CPUC approval of reasonable cost recovery.

Palo Verde Steam Generators

The steam generators at the Palo Verde Nuclear Generating Station (Palo Verde), in which SCE owns a 15.8% interest, have the same design and material properties as the San Onofre units. During 2003, the Palo Verde Unit 2 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture of two additional sets of steam generators for installation in Units 1 and 3. The Palo Verde owners expect that these steam generators will be installed in Units 1 and 3 in the 2005 to 2008 time frame. SCE's share of the costs of manufacturing and installing all the replacement steam generators at Palo Verde is estimated to be about $110 million; SCE plans to seek recovery of that amount through the rate-making process.

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 Statement of Cash Flows.

Results of Operations

Earnings from Continuing Operations

SCE earnings from continuing operations in 2003 were $882 million, compared to earnings of $1.2 billion in 2002 and earnings of $2.4 billion in 2001. SCE's 2002 earnings included a $480 million benefit related to the implementation of the CPUC URG decision. SCE's 2001 earnings included a $2.1 billion (after tax) benefit resulting from the reestablishment of procurement-related regulatory assets and liabilities as a result of the PROACT resolution and recovery of $178 million (after tax) of previously written off generation-related regulatory assets, partially offset by $328 million (after tax) of net undercollected transition costs incurred between January and August 2001. Excluding the $480 million benefit in 2002 and the net $2.0 billion benefit in 2001, SCE's earnings from continuing operations were $767 million in 2002 and $408 million in 2001. The $115 million increase between 2003 and 2002 results from the net effect of the resolution of several regulatory proceedings in 2003 and 2002. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions, tax impacts from the FERC rate case, and the final disposition of the PROACT which had been created to record the recovery of SCE's procurement-related obligations. The positive effects of these factors on 2003 earnings were partially offset by the implementation in 2002 of the CPUC's URG decision and PBR rewards received in 2002. SCE's results also included higher depreciation expense and lower net interest income, partially offset by higher FERC and PBR revenue. The $359 million increase between 2002 and 2001 primarily reflects increased revenue resulting from the CPUC's 2002 decision in SCE's PBR proceeding, increased earnings from SCE's larger rate base in 2002 compared to 2001, lower interest expense, PBR rewards from prior years and increased income from San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3. The increase was partially offset by higher operating and maintenance expense.

Based on the CPUC's January 23, 2002 PROACT resolution, SCE was able to conclude that $3.6 billion in regulatory assets previously written off were probable of recovery through the rate-making process as of December 31, 2001. As a result, SCE's December 31, 2001 consolidated income statement included a $3.6 billion credit to provisions for regulatory adjustment clauses and a $1.5 billion charge to income tax expense, to reflect the $2.1 billion (after tax) credit to earnings.

Operating Revenue

SCE's retail sales represented approximately 91%, 96% and 94% of operating revenue in 2003, 2002, and 2001, respectively. Due to warmer weather during the summer months, operating revenue during the third quarter of each year is significantly higher than other quarters.

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

In millions Year ended December 31,	2003 vs. 2002	2002 vs. 2001
Operating revenue		
Rate changes (including surcharges)	$ (677)	$ 563
Direct access credit	471	(604)
Sales volume changes	(60)	696
Sales for resale	394	(11)
Other	20	(64)
Total	$ 148	$ 580

Total operating revenue increased by $148 million in 2003 (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, partially offset by the recognition of revenue from the CPUC-authorized temporary surcharge collected in 2002, used to recover costs incurred in 2003 (see "Regulatory Matters—Generation and Power Procurement—Temporary Surcharges"). The increase in operating revenue due to direct access credits resulted from a net 1¢-per-kWh decrease in credits given to direct access customers. The reduction in electric revenue resulting from changes in sales volume was mainly due to an increase in the amount allocated to the CDWR for bond and direct access exit fees (see discussion below), partially offset by an increase in kWh sold due to warmer weather in 2003 as compared to 2002. Sales for resale revenue increased due to a greater amount of excess energy at SCE in 2003 as compared to 2002. As a result of CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times and is resold in the energy markets.

Operating revenue increased by $580 million in 2002 as compared to 2001 (as shown in the table above). The increase in operating revenue due to rate changes resulted from a 3¢-per-kWh surcharge authorized by the CPUC as of March 27, 2001. The decrease in operating revenue due to direct access credits resulted from an increase in credits given to direct access customers due to a significant increase in the number of direct access customers. The increase in operating revenue resulting from changes in sales volume was primarily due to SCE providing its customers with a greater volume of energy generated from its own generating plants and power-purchase contracts, rather than the CDWR purchasing power on behalf of SCE's customers.

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 direct access exit fees (beginning January 1, 2003) are remitted to the CDWR and are not recognized as revenue by SCE. These amounts were $1.7 billion, $1.4 billion, and $2.0 billion for the years ended December 31, 2003, 2002, and 2001, respectively.

Operating Expenses

Fuel expense increased in 2002 primarily due to fuel related costs SCE related to a payment received under a settlement agreement with Peabody associated with Mohave.

Purchased-power expense increased in 2003 and decreased in 2002. The 2003 increase was mainly due to higher expenses resulting from SCE's resumption of power procurement on January 1, 2003. The higher expenses resulted from an increase in the number of bilateral contracts entered into during 2003 and an increase in energy purchased in 2003. The increase also includes higher expenses related to power purchased from QFs, mainly due to higher spot natural gas prices in 2003 as compared to 2002. The 2002 decrease resulted primarily from lower expenses related to power purchased from QFs, bilateral contracts and interutility contracts, mainly due to lower spot natural gas prices in 2002 as compared to 2001. In addition, the decrease reflects the absence of PX/ISO purchased-power expense after mid-January 2001.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. These contracts expire on various dates through 2025. Energy payments to gas-fired cogeneration 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, compared with an average of 3.1¢-per-kWh during the period of January and April 2002. During 2003, spot natural gas prices were higher compared to the same period in 2002. During 2002, spot natural gas prices were significantly lower than the same periods in 2001.

Provisions for regulatory adjustment clauses – net decreased in 2003 and increased in 2002. The 2003 decrease was mainly due to lower overcollections used to recover the PROACT balance, the implementation of the CPUC-authorized customer rate-reduction plan, a net increase in energy procurement costs and favorable resolution of several regulatory proceedings. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions and the final disposition of the PROACT. The decrease was partially offset by the implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions recorded in 2002. The 2002 increase was primarily due to the establishment of the PROACT regulatory asset in 2001, overcollections used to recover the PROACT balance and revenue collected to recover the rate reduction bond regulatory asset, partially offset by the impact of SCE's implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions.

As a result of the URG decision received in 2002, SCE reestablished regulatory assets previously written off (approximately $1.1 billion) related to its nuclear plant investments, purchased-power settlements and flow-through taxes, and decreased the PROACT balance by $256 million, all retroactive to January 1, 2002. The impact of the URG decision is reflected in the 2002 financial statements as a credit (decrease) to the provisions for regulatory adjustment clauses of $644 million, partially offset by an increase in deferred income tax expense of $164 million, for a net credit to earnings of $480 million. As a result of the CPUC decision that modified the PBR mechanism, SCE recorded a $136 million credit (decrease) to the provisions for regulatory adjustment clauses in the second quarter of 2002, to reflect undercollections in CPUC-authorized revenue resulting from changes in retail rates.

Other operating and maintenance expense increase in 2003 was mainly due to higher health-care costs, higher spending on certain CPUC-authorized programs, higher transmission access charges and costs incurred in 2003 related to the removal of dead, dying and diseased trees and vegetation associated with the bark beetle infestation (see "Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"). Other operation and maintenance expense increase in 2002 was primarily due to the San Onofre Unit 2 refueling outage in 2002, increases in transmission and distribution maintenance and inspection activities, and temporary cost containment efforts that took place in 2001. The 2002 increases were partially offset by lower expenses related to balancing accounts.

Depreciation, decommissioning and amortization expense increased in both 2003 and 2002. The 2003 increase was mainly due to an increase in depreciation expense associated with additions to transmission and distribution assets and an increase in nuclear decommissioning expense. The 2003 increase was partially offset by a change in the amortization period for San Onofre recorded in the third quarter of 2002 based on the implementation of a CPUC decision. The increase in 2002 was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets and an increase in SCE's nuclear decommissioning expense. A 1994 CPUC decision allowed SCE to accelerate the recovery of its nuclear-related assets while deferring the recovery of its distribution-related assets for the same amount. Beginning in January 2002, the CPUC approved the commencement of recovery of SCE's deferred distribution assets. In addition, the increases reflect amortization expense on the nuclear regulatory asset reestablished during second quarter 2002 based on the URG decision.

Other Income and Deductions

Interest and dividend income decreased in 2003 and increased in 2002. The 2003 decrease was mainly due to lower interest income on the PROACT balance as well as lower interest income from lower average cash balances, compared to the same period in 2002. The 2002 increase was mainly due to the interest income earned on the PROACT balance. The 2002 increase was partially offset by lower interest income due to lower average cash balances and lower interest rates during 2002, as compared to 2001.

Other nonoperating income decreased slightly in 2003 and increased in 2002. The 2003 decrease was mainly due to property condemnation settlements received in 2002, with no comparable settlements received in 2003, almost entirely offset by the recognition of 2000 and 2001 Palo Verde performance rewards approved by the CPUC during 2003. The 2002 increase was primarily due to property condemnation settlements received, partially offset by PBR incentive awards for 1999 and 2000, which were approved by the CPUC and recorded in 2001.

Interest expense – net of amounts capitalized decreased in both 2003 and 2002. The 2003 decrease was due to lower interest expense at SCE due to the accrual of interest in 2002 related to the 2001 and early 2002 suspension of payments for purchased power (these suspended payments were paid in March 2002), as well as lower interest expense on long-term debt resulting from the early retirement of debt. Interest expense – net in 2003 reflects a change in the classification of dividend payments on preferred securities to interest expense – net from dividends on preferred securities. 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. The 2002 decrease is mainly due to lower short-term debt balances in 2002, compared to 2001 and lower interest expense related to the suspension of payments for purchased power during 2001, which were subsequently paid in early 2002. The 2002 decrease was partially offset by an increase in interest expense on long-term debt due to higher long-term debt balances in 2002, compared to 2001.

Other nonoperating deductions increased in 2003 and decreased in 2002. The variance in both 2003 and 2002 was primarily due to the reversal of accruals for regulatory matters in 2002.

Income Taxes

Income taxes decreased in both 2003 and 2002. The 2003 and 2002 decrease was primarily due to reductions in pre-tax income and the favorable resolution of tax audit issues. The 2003 decrease also resulted from the favorable resolution of a FERC rate case. The 2002 decrease also resulted from the reestablishment of tax-related regulatory assets upon implementation of the URG decision.

SCE's federal and state statutory tax rate was 40.551% for all years presented. 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 favorable resolution of tax audit issues. The lower effective tax rate of 34% realized in 2002 was primarily due to the reestablishment of tax-related regulatory assets upon implementation of the URG decision as well as favorable resolution of tax audit issues.

Earnings from Discontinued Operations

SCE's earnings from discontinued operations in 2003, included a $44 million (after-tax) gain on the sale of SCE's fuel oil pipeline business and operating results of $6 million.

Historical Cash Flow Analysis

Cash Flows from Operating Activities

Net cash provided by operating activities was $2.7 billion in 2003, $631 million in 2002 and $3.3 billion in 2001. The 2003 increase was mainly due to the March 2002 repayment of past-due obligations, as well as the timing of cash receipts and disbursements related to working capital items. The 2002 decrease in cash provided by operating activities was mainly due to the March 2002 repayment of past-due obligations, partially offset by higher overcollections used to recover regulatory assets resulting from the CPUC-approved surcharges (1¢ per kWh in January 2001 and 3¢ per kWh in June 2001).

Cash used by operating activities from discontinued operations in 2003 primarily reflects operating activities at SCE's fuel oil pipeline business.

Cash Flows from Financing Activities

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

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 2003 financing activities also include a dividend payment of $945 million of equity to Edison International.

During the first quarter of 2002, SCE paid $531 million of matured commercial paper and remarketed $196 million of the $550 million of pollution-control bonds repurchased during December 2000 and early 2001. Also during the first quarter of 2002, SCE replaced the $1.65 billion credit facility with a $1.6 billion financing and made a payment of $50 million to retire the entire credit facility. Throughout the year, SCE paid approximately $1.2 billion of maturing long-term debt. The $1.6 billion financing included a $600 million, one-year term loan due March 3, 2003. SCE prepaid $300 million of this loan in August 2002.

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 electric industry 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 remaining series of outstanding rate reduction notes have scheduled maturities through 2007, with interest rates ranging from 6.38% to 6.42%. 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.

Cash Flows from Investing Activities

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

Additions to SCE's property and plant during 2003 were approximately $1.2 billion, primarily for transmission and distribution assets. Additions to SCE's property and plant during 2002 were approximately $1.0 billion, primarily for transmission and distribution assets.

Investing cash flows from discontinued operations in 2003 represents the proceeds received from SCE's sale of its fuel oil pipeline business.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $32 million per year. The fair value of decommissioning SCE's nuclear power facilities is $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. As of December 31, 2003, the decommissioning trust balance was $2.5 billion. The CPUC has set certain restrictions related to the investments of these trusts. 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. SCE's costs to decommission San Onofre Unit 1 are paid from the nuclear decommissioning trust funds. These withdrawals from the decommissioning trusts are netted with the contributions to the trust funds in the Consolidated Statements of Cash Flows.

DISPOSITION AND DISCONTINUED OPERATIONS

On July 10, 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. Due to immateriality, the results of this unit for prior years have not been restated and are reflected as part of continuing operations.

ACQUISITION

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new 1,054-megawatt, combined-cycle, natural gas-fired power plant currently being developed in Redlands, California. Mountainview Power Company LLC would sell all the output of the power plant to SCE pursuant to a 30-year tolling power-purchase agreement. The power-purchase agreement would be a cost-based contract providing for recovery of investment, fixed and variable costs, and a regulated rate of return, over the 30-year life of the contract. On December 18, 2003, the CPUC approved the Mountainview power-purchase agreement, subject to SCE receiving a FERC decision approving the agreement without any modifications that would have potential rate impacts. On February 25, 2004, the FERC granted conditional approval of the Mountainview power-purchase agreement. On March 1, 2004, a CPUC administrative law judge issued a proposed decision that would accept the conditions in the FERC approval of the power-purchase agreement. The matter is scheduled to be considered by the CPUC at its meeting on March 16, 2004. On February 28, 2004, SCE exercised its option to purchase Mountainview Power LLC. SCE currently anticipates that it will close the purchase before the end of March 2004 and recommence construction of the project immediately thereafter. SCE estimates that the project will be completed in March 2006 at a cost of approximately $600 million, excluding financing costs. SCE expects to finance the capital costs of the project with debt and equity at the utility level consistent with its authorized capital structure.

CRITICAL ACCOUNTING POLICIES

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

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, and (4) if an impairment exists, the fair value of the asset or asset group. Factors 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.

During the fourth quarter of 2002, SCE assessed the impairment of Mohave due to the probability of a plant shutdown 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. However, in accordance with accounting principles for rate regulated companies, this incurred cost was deferred and recorded as a regulatory asset, due to the expectation that the unrecovered book value of Mohave at the time of shutdown will be recovered through the rate-making process. See "Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings," and "—Rate Regulated Enterprises."

Income Taxes

The accounting standard for income taxes requires the asset and liability approach for financial accounting and reporting for deferred income taxes. SCE 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 of the jurisdictions 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. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as deemed necessary.

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 the postretirement health care plan. 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. At the December 31, 2003 measurement date, SCE used a discount rate of 6% for pensions and 6.25% for postretirement benefits other than pensions (PBOP) that represented the market interest rate for high-quality fixed income investments.

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 8.5% for pensions and 8.2% for PBOP. A portion of PBOP trust asset returns are subject to taxation, so the 8.2% figure above is determined on an after-tax basis. Actual returns on pension plan assets were 27.6%, 7.3%, and 10.8% for the one-year, five-year and ten-year periods ended December 31, 2003, respectively. Actual returns on PBOP plan assets were 26%, 2.2%, and 9.1% over the same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

At December 31, 2003, SCE's pension plans included $2.8 billion in projected benefit obligation (PBO), $2.4 billion in accumulated benefit obligation (ABO) and $2.8 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $205 million, and a 1% increase would decrease the PBO by $191 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would increase pension expense by $22 million.

SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for ratemaking purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with ratemaking methods and pension expense or income calculated in accordance with accounting standards, is accumulated in a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2003, this cumulative difference amounted to a regulatory liability of $140 million, meaning that the ratemaking method has resulted in recognizing

$140 million more in expense than the accounting method since implementation of the pension accounting standard in 1987.

Under accounting standards, if the ABO 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 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 ABO.

See "Other Developments—Employee Compensation and Benefit Plans" for information related to SCE's cash balance pension plan.

At December 31, 2003, SCE's PBOP plan included $2.1 billion in PBO and $1.4 billion in plan assets. Total expense for these plans was $117 million for 2003. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $305 million and annual aggregate service and interest costs by $27 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $248 million and annual aggregate service and interest costs by $22 million.

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 has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense above do not reflect the effects of the Act on SCE's plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require SCE to restate previously reported information.

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, 2003, the Consolidated Balance Sheets included regulatory assets, less regulatory liabilities, of $234 million. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as deemed necessary.

SCE applied judgment in the use of the above principles when it: (1) created the $3.6 billion PROACT regulatory asset in the fourth quarter of 2001; (2) restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision in the second quarter of 2002; and (3) established a $61 million regulatory asset related to the impaired Mohave in the fourth quarter of 2002. In all instances, SCE recorded corresponding credits to earnings upon concluding that such incurred costs were probable of recovery in the future. See further discussion in "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings" and "Regulatory Matters—Generation and Power Procurement—PROACT Regulatory Asset," "—Utility-Retained Generation," and "—Mohave Generating Station and Related Proceedings" sections.

NEW ACCOUNTING PRINCIPLES

On January 1, 2003, SCE adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this standard and the recovery of costs through the rate-making process. Regulatory assets and liabilities may also be recorded when it is probable that the ARO will be recovered through the rate-making process.

SCE's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized AROs associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued $2.3 billion to decommission its nuclear facilities and $12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, $298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining $2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the $2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately $2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by $303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a $354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a $235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO ($128 million) and depreciation expense on the new asset ($15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from $2.02 billion to $2.08 billion in 2003, with the $128 million in accretion partially offset by $68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear facilities totaled approximately $2.07 billion and its nuclear decommissioning trust assets had a fair value of $2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been $1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any impact on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations ($2.02 billion at December 31, 2003 and $1.92 billion at December 31, 2002) are included in regulatory liabilities.

Effective July 1, 2003, SCE adopted a new accounting standard, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which required issuers to classify certain freestanding financial instruments as liabilities. These freestanding liabilities include mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets and certain obligations to issue a variable number of shares. Effective July 1, 2003, SCE reclassified its preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. This item was previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on this instrument are included in interest expense – net of amounts capitalized on SCE's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on SCE's financial statements as of December 31, 2003.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE. This Interpretation is effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 long-term power-purchase contracts with independent power producers that own QFs. SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced by these facilities, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on 1) whether these power generators are considered to be VIEs, and 2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power-purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. Edison Mission Energy, a wholly owned subsidiary of Edison International, has 49% to 50% ownership in four QF partnerships that have long-term power sales contracts with SCE. Edison Mission Energy accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the related-party nature of this transaction, it is likely that these four QFs could be consolidated by either Edison Mission Energy or SCE.

COMMITMENTS

SCE's commitments for the years 2004 through 2008 and thereafter are estimated below:

In millions	2004	2005	2006	2007	2008	Thereafter
Long-term debt maturities and sinking fund requirements	$ 371	$ 442	$ 446	$ 1,251	$ —	$1,982
Estimated noncancelable lease payments	13	10	7	6	4	8
Fuel supply contract payments	182	126	58	66	51	495
Purchased-power capacity payments	682	663	637	637	444	3,621
Unconditional purchase obligations	10	10	10	10	10	89
Preferred securities redemption requirements	9	9	9	69	54	—

SCE's projected construction expenditures for 2004 are $1.9 billion, including the investment and projected construction expenditures for the Mountainview project (see "Acquisition"). These expenditures are planned to be financed primarily through cash generated from operations and borrowings.

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates.

Fuel Supply Contracts

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. Certain SCE gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered. In addition, fuel supply contract payments include payments for nuclear fuel commitments.

Power Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. 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 balance sheets. In addition, SCE entered into bilateral forward power contracts during 2003, which contain capacity payment provisions.

Unconditional Purchase Obligations

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power-purchase contracts (approximately $28 million).

Other Commitments

SCE's expected contributions (all by the employer) for its pension and PBOP plans are approximately $33 million and $100 million, respectively, for the year ended December 31, 2004. These amounts are subject to change based on, among other things, the limits established for federal tax deductibility (pension plan) and the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (PBOP plan).

The management of Southern California Edison Company (SCE) is responsible for the integrity and objectivity of the accompanying financial statements. The statements have been prepared in accordance with accounting principles generally accepted in the United States and are based, in part, on management estimates and judgment.

SCE maintains systems of internal control to provide reasonable, but not absolute, assurance that assets are safeguarded, transactions are executed in accordance with management's authorization and the accounting records may be relied upon for the preparation of the financial statements. There are limits inherent in all systems of internal control, the design of which involves management's judgment and the recognition that the costs of such systems should not exceed the benefits to be derived. SCE believes its systems of internal control achieve this appropriate balance. These systems are augmented by internal audit programs through which the adequacy and effectiveness of internal controls and policies and procedures are monitored, evaluated and reported to management. Actions are taken to correct deficiencies as they are identified.

SCE's independent auditors, PricewaterhouseCoopers LLP, are engaged to audit the financial statements in accordance with auditing standards generally accepted in the United States and to express an informed opinion on the fairness, in all material respects, of SCE's reported results of operations, cash flows and financial position.

As a further measure to assure the ongoing objectivity of financial information, the Audit Committee of the Board of Directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent auditors and internal auditors, who have unrestricted access to the committee. The committee annually appoints a firm of independent auditors (who are ultimately responsible to the committee) to conduct audits of SCE's financial statements; considers the independence of such firm and the overall adequacy of the audit scope and SCE's systems of internal control; reviews financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

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

Tho M. Noonan

Thomas M. Noonan
Vice President
and Controller

Alan J. Fohrer
Chief Executive Officer

March 10, 2004

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in common shareholder's equity present fairly, in all material respects, the financial position of Southern California Edison Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for the years then ended 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 auditing standards generally accepted in the United States of America, which 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. The financial statements of the Company for the year ended December 31, 2001 were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on the financial statements in their report dated March 25, 2002.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of January 1, 2003, and financial instruments with characteristics of both debt and equity as of July 1, 2003.

PricewaterhouseCoopers LLP

Los Angeles, California
March 10, 2004

THE FOLLOWING REPORT IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP

To Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, a California corporation) and its subsidiaries as of December 31, 2001, and 2000, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and changes in common shareholder's equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of SCE's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of SCE and its subsidiaries as of December 31, 2001, and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Los Angeles, California
March 25, 2002

In millions Year ended December 31,	2003	2002	2001
Operating revenue	**$ 8,854**	$ 8,706	$ 8,126
Fuel	**235**	243	212
Purchased power	**2,786**	2,016	3,770
Provisions for regulatory adjustment clauses – net	**1,138**	1,502	(3,028)
Other operation and maintenance	**2,054**	1,926	1,771
Depreciation, decommissioning and amortization	**882**	780	681
Property and other taxes	**168**	117	112
Net gain on sale of utility plant	**(5)**	(5)	(9)
Total operating expenses	**7,258**	6,579	3,509
Operating income	**1,596**	2,127	4,617
Interest and dividend income	**100**	262	215
Other nonoperating income	**72**	75	57
Interest expense – net of amounts capitalized	**(457)**	(584)	(785)
Other nonoperating deductions	**(41)**	9	(38)
Income from continuing operations before tax	**1,270**	1,889	4,066
Income tax	**388**	642	1,658
Income from continuing operations	**882**	1,247	2,408
Income from discontinued operations	**82**	—	—
Income tax on discontinued operations	**32**	—	—
Net income	**932**	1,247	2,408
Dividends on preferred stock	**10**	19	22
Net income available for common stock	**$ 922**	$ 1,228	$ 2,386

Consolidated Statements of Comprehensive Income

In millions Year ended December 31,	2003	2002	2001
Net income	**$ 932**	$ 1,247	$ 2,408
Other comprehensive income, net of tax:			
Minimum pension liability adjustment	**(4)**	(5)	—
Cumulative effect of change in accounting for derivatives	—	—	398
Unrealized gain (loss) on and amortization of cash flow hedges	**1**	11	(420)
Comprehensive income	**$ 929**	$ 1,253	$ 2,386

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

Consolidated Balance Sheets

In millions December 31,	2003	2002
ASSETS		
Cash and equivalents	**$ 95**	$ 992
Restricted cash	**66**	47
Receivables, less allowances of $30 and $36 for uncollectible accounts at respective dates	**751**	767
Accrued unbilled revenue	**408**	437
Fuel inventory	**10**	12
Materials and supplies, at average cost	**168**	153
Accumulated deferred income taxes – net	**508**	299
Regulatory assets – net	**—**	459
Prepayments and other current assets	**58**	57
Total current assets	**2,064**	3,223
Nonutility property – less accumulated provision for depreciation of $24 and $15 at respective dates	**116**	103
Nuclear decommissioning trusts	**2,530**	2,210
Other investments	**153**	235
Total investments and other assets	**2,799**	2,548
Utility plant, at original cost:		
Transmission and distribution	**14,861**	14,202
Generation	**1,371**	1,348
Accumulated provision for depreciation	**(4,386)**	(4,057)
Construction work in progress	**600**	529
Nuclear fuel, at amortized cost	**141**	153
Total utility plant	**12,587**	12,175
Regulatory assets – net	**510**	—
Other deferred charges	**506**	629
Total deferred charges	**1,016**	629
Assets of discontinued operations	**—**	62
Total assets	**$ 18,466**	$ 18,637

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

In millions, except share amounts December 31,	2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**$ 200**	$ —
Long-term debt due within one year	**371**	1,671
Preferred stock to be redeemed within one year	**9**	9
Accounts payable	**891**	665
Accrued taxes	**556**	699
Regulatory liabilities – net	**276**	—
Other current liabilities	**1,258**	1,469
Total current liabilities	**3,561**	4,513
Long-term debt	**4,121**	4,525
Accumulated deferred income taxes – net	**2,726**	2,915
Accumulated deferred investment tax credits	**136**	148
Customer advances and other deferred credits	**427**	609
Power-purchase contracts	**213**	309
Preferred stock subject to mandatory redemption	**141**	—
Accumulated provision for pensions and benefits	**330**	356
Asset retirement obligations	**2,084**	—
Regulatory liabilities – net	—	393
Other long-term liabilities	**243**	209
Total deferred credits and other liabilities	**6,300**	4,939
Total liabilities	**13,982**	13,977
Commitments and contingencies (Notes 2, 9 and 10)		
Preferred stock subject to mandatory redemption	—	147
Common stock (434,888,104 shares outstanding at each date)	**2,168**	2,168
Additional paid-in capital	**338**	340
Accumulated other comprehensive loss	**(19)**	(16)
Retained earnings	**1,868**	1,892
Total common shareholder's equity	**4,355**	4,384
Preferred stock not subject to mandatory redemption	**129**	129
Total shareholders' equity	**4,484**	4,513
Total liabilities and shareholders' equity	**$ 18,466**	$ 18,637

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

In millions Year ended December 31,	2003	2002	2001
Cash flows from operating activities:			
Income from continuing operations	**$ 882**	$ 1,247	$ 2,408
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**882**	780	681
Other amortization	**101**	106	82
Deferred income taxes and investment tax credits	**(49)**	(640)	1,313
Regulatory assets – long-term – net	**495**	1,860	(3,135)
Gas options	**75**	14	(91)
Other assets	**121**	7	(68)
Other liabilities	**(374)**	132	17
Changes in working capital:			
Receivables and accrued unbilled revenue	**45**	338	(243)
Regulatory assets – short-term – net	**697**	(376)	(278)
Fuel inventory, materials and supplies	**(13)**	(11)	(16)
Prepayments and other current assets	**(22)**	41	(21)
Accrued interest and taxes	**(143)**	(191)	365
Accounts payable and other current liabilities	**13**	(2,676)	2,251
Operating cash flows from discontinued operations	**(34)**	—	—
Net cash provided by operating activities	**2,676**	631	3,265
Cash flows from financing activities:			
Long-term debt issuance costs	**(11)**	(32)	—
Long-term debt repaid	**(1,263)**	(1,200)	—
Bonds remarketed (repurchased) and funds held in trust – net	—	191	(130)
Redemption of preferred stock	**(6)**	(100)	—
Rate reduction notes repaid	**(246)**	(246)	(246)
Nuclear fuel financing – net	—	(59)	(21)
Short-term debt financing – net	**(4)**	(527)	676
Dividends paid	**(955)**	(40)	(1)
Net cash provided (used) by financing activities	**(2,485)**	(2,013)	278
Cash flows from investing activities:			
Additions to property and plant – net	**(1,161)**	(1,046)	(688)
Contributions to nuclear decommissioning trusts – net	**(86)**	(12)	(36)
Sales of investments in other assets	**13**	18	12
Investing cash flows from discontinued operations	**146**	—	—
Net cash used by investing activities	**(1,088)**	(1,040)	(712)
Net increase (decrease) in cash and equivalents	**(897)**	(2,422)	2,831
Cash and equivalents, beginning of year	**992**	3,414	583
Cash and equivalents, end of year, continuing operations	**$ 95**	$ 992	$ 3,414

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 (Deficit)	Total Common Shareholder's Equity
Balance at December 31, 2000	$ 2,168	$ 334	$ —	$ (1,722)	$ 780
Net income				2,408	2,408
Cumulative effect of change in accounting for derivatives			398		398
Unrealized loss on and amortization of cash flow hedges			(420)		(420)
Dividends accrued on preferred stock				(22)	(22)
Capital stock expense and other		2			2
Balance at December 31, 2001	$ 2,168	$ 336	$ (22)	$ 664	$ 3,146
Net income				1,247	1,247
Minimum pension liability adjustment			(9)		(9)
Tax effect			4		4
Amortization of loss on cash flow hedges			4		4
Tax effect			7		7
Dividends accrued on preferred stock				(19)	(19)
Capital stock expense and other		4			4
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
Unrealized loss on and amortization of cash flow hedges			2		2
Tax effect			(1)		(1)
Dividends declared on common stock				(945)	(945)
Dividends declared on preferred stock				(10)	(10)
Capital stock expense and other		(2)		(1)	(3)
Balance at December 31, 2003	$ 2,168	$ 338	$ (19)	$ 1,868	$ 4,355

Authorized common stock is 560 million shares with no par value.

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 and its subsidiaries. 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). In 1997, due to changes in the rate recovery of generation-related assets, SCE began using accounting principles applicable to enterprises in general for its investment in generation facilities. In April 2002, SCE reapplied accounting principles for rate-regulated enterprises to assets that were returned to cost-based regulation under the utility-retained generation (URG) decision.

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 regulatory matters, financial instruments, income taxes, pension and postretirement benefits other than pensions, decommissioning and contingencies are further discussed in Notes 2, 3, 6, 7, 9 and 10 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 time deposits and other investments with original maturities of three months or less. All investments are classified as available for sale. For a discussion of restricted cash, see "Restricted Cash."

Debt and Equity Investments

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.

Fuel Inventory

Fuel inventory is valued under the last-in, first-out method for fuel oil, and under the first-in, first-out method for coal.

New Accounting Principles

On January 1, 2003, SCE adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this standard and the recovery of costs through the rate-making process. Regulatory assets and liabilities may also be recorded when it is probable that the ARO will be recovered through the rate-making process.

SCE's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized AROs associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued \$2.3 billion to decommission its nuclear facilities and \$12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, \$298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining \$2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the \$2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately \$2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by \$303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a \$354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a \$235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO (\$128 million) and depreciation expense on the new asset (\$15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from \$2.02 billion to \$2.08 billion in 2003, with the \$128 million in accretion partially offset by \$68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear facilities totaled approximately \$2.07 billion and its nuclear decommissioning trust assets had a fair value of \$2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been \$1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any impact on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations (\$2.02 billion at December 31, 2003 and \$1.92 billion at December 31, 2002) are included in regulatory liabilities.

Effective July 1, 2003, SCE adopted a new accounting standard, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which required issuers to classify certain freestanding financial instruments as liabilities. These freestanding liabilities include mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets and certain obligations to issue a variable number of shares. Effective July 1, 2003, SCE reclassified its preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. This item was previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on this instrument are included in interest expense – net of amounts capitalized on SCE's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change. See disclosures regarding the preferred stock in Note 3.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on SCE's financial statements as of December 31, 2003.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE. This Interpretation is effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 long-term power-purchase contracts with independent power producers that own qualifying facilities (QFs). SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced by these facilities, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on 1) whether these power generators are considered to be VIEs, and 2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. Edison Mission Energy, a wholly owned subsidiary of Edison International, has 49% to 50% ownership in four QF partnerships that have long-term power sales contracts with SCE. Edison Mission Energy accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the related-party nature of this transaction, it is likely that these four QFs could be consolidated by either Edison Mission Energy or SCE.

Nuclear

SCE's nuclear plant investments are recorded as a regulatory asset on its balance sheets. This classification does not affect the rate-making treatment for these assets. SCE had been recovering its investments in San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 and Palo Verde Nuclear Generating Station (Palo Verde) on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were recovered through an incentive pricing plan that allows SCE to receive about 4¢ per kilowatt-hour (kWh) through 2003. Any differences between these costs and the incentive price would flow through to shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were subject to balancing account treatment through the effective date of the 2003 general rate case.

The nuclear rate-making plans were to continue for rate-making purposes at least through the 2003 general rate case effective date for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues as of December 31, 2000, SCE was no longer able to conclude that the unamortized nuclear investment was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time. As a result of the CPUC's April 4, 2002 decision that returned SCE's URG assets to cost-based ratemaking, SCE reestablished for financial reporting purposes its unamortized nuclear investment and related flow-through taxes, retroactive to August 31, 2001, based on a 10-year recovery period, effective January 1, 2001, with a corresponding credit to earnings. SCE adjusted the procurement-related obligations account (PROACT) regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

In a September 2001 decision, the CPUC granted SCE's request to continue the current rate-making treatment for Palo Verde, including the continuation of the existing nuclear unit incentive procedure with a 5¢ per kWh cap on replacement power costs, until resolution of SCE's next general rate case or further CPUC action. Palo Verde's existing nuclear unit incentive procedure calculates a reward for performance of any unit above an 80% capacity factor for a fuel cycle. The San Onofre Units 2 and 3 incentive rate-making plan continued until December 31, 2003. In its general rate case, SCE has requested to transition San Onofre Units 2 and 3 back to traditional cost-of-service ratemaking on January 1, 2004, and to return Palo Verde to traditional cost-of-service ratemaking upon the effective date of the decision on that application.

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2003	2002	2001
Property condemnation settlement	$ —	$ 38	$ —
Allowance for funds used during construction	27	19	16
Performance-based incentive award	21	—	21
Other	24	18	20
Total other nonoperating income	**$ 72**	$ 75	$ 57
Provisions for regulatory issues and refunds	$ —	$ (42)	$ 7
Other	41	33	31
Total other nonoperating deductions	**$ 41**	$ (9)	$ 38

Planned Major Maintenance

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

Purchased Power

SCE purchased power through the California Power Exchange (PX) and California Independent System Operator (ISO) from April 1998 through mid-January 2001. SCE has bilateral forward contracts with other entities and power-purchase contracts with other utilities and independent power producers classified as QFs. Purchased-power detail is provided below:

In millions Year ended December 31,	2003	2002	2001
PX/ISO:			
Purchases	$ 284	$ 75	$ 775
Generation sales	—	—	324
Purchased power – PX/ISO – net	284	75	451
Purchased power – bilateral contracts	342	61	188
Purchased power – interutility/QF contracts	2,160	1,880	3,131
Total	**$ 2,786**	$2,016	$ 3,770

Net PX/ISO amounts for 2002 reflect only billing adjustments. These billing adjustments are recovered through the PROACT and have no impact on earnings. Net PX/ISO amounts for 2003 include ISO imbalance purchases and billing adjustments.

From January 17, 2001 to December 31, 2002, the California Department of Water Resources (CDWR) purchased power for delivery to SCE's customers in an amount equal to the difference between customer requirements and supplies provided through QF and bilateral contracts, and SCE's utility retained generation. Effective January 1, 2003, SCE assumed responsibility for power requirements not met by the CDWR. Power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

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.

SCE assessed the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001 decisions. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. SCE was unable to conclude that its generation-related regulatory assets were probable of recovery through the rate-making process as of December 31, 2000. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings at that time, to write off various regulatory assets.

In accordance with an October 2001 settlement agreement between the CPUC and SCE, the CPUC passed a resolution on January 23, 2002, allowing SCE to establish the procurement-related obligations account (PROACT) regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. SCE fully recovered the PROACT balance during July 2003 and on August 1, 2003, transferred the PROACT overcollection to a new energy resource recovery account regulatory balancing account. The new balancing account acts as a mechanism to recover SCE's fuel costs related to its generating stations, purchased-power costs related to cogeneration and renewable contracts, existing interutility and bilateral contracts that were entered into prior to January 17, 2001, and new procurement-related costs that SCE began incurring on January 1, 2003, the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers.

Based on the CPUC's April 2002 decision related to SCE's URG assets, during the second quarter of 2002, SCE reestablished for financial reporting purposes regulatory assets related to its unamortized nuclear facilities, purchased-power settlements and flow-through taxes.

Due to the current status of the Mohave Generating Station (Mohave) and Related Proceedings (discussed in Note 2), SCE has concluded that it is probable Mohave will be shut down at the end of 2005 and that its book value must be reduced to fair value in accordance with an impairment-related accounting standard. Based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through the rate-making mechanism discussed in its May 17, 2002 application and again in its January 30, 2003 supplemental testimony, and in accordance with accounting standards for rate-regulated enterprises, SCE reclassified for financial reporting purposes approximately $61 million of Mohave's $88 million book value (at December 31, 2002) to a regulatory asset as of December 31, 2002.

As part of a new accounting standard, Accounting for Asset Retirement Obligations, SCE capitalized the initial cost of the ARO into a nuclear-related ARO regulatory asset, and also recorded a nuclear-related asset retirement obligation (ARO) regulatory liability for the present value of the obligation, and an ARO regulatory liability as a result of timing differences between the recognition of costs as recorded in accordance with this standard and the recovery of the related asset retirement costs through the rate-making process. The ARO regulatory liability defers the impact on earnings of the change in accounting principle. See further discussion in "New Accounting Principles."

SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. Upon implementation of the new accounting standard for AROs, SCE reversed the decommissioning amounts collected for assets legally required to be removed and recorded the fair value of this ARO (included in the deferred credits and other liabilities section of the consolidated balance sheet). The cost of removal amounts collected for assets not legally required to be removed remains in regulatory liabilities as of December 31, 2003.

Regulatory assets, less regulatory liabilities, included in the consolidated balance sheets are:

In millions December 31,	**2003**	2002
Current:		
PROACT – net	**$ —**	$ 574
Regulatory balancing accounts and other – net	**(276)**	(115)
	(276)	459
Long-term:		
Flow-through taxes – net	**974**	1,336
Rate reduction notes – transition cost deferral	**949**	1,215
Unamortized nuclear investment – net	**601**	630
Nuclear-related ARO investment – net	**288**	—
Unamortized coal plant investment – net	**66**	61
Unamortized loss on reacquired debt	**222**	237
Environmental remediation	**71**	70
ARO	**(720)**	—
Costs of removal	**(2,020)**	(4,231)
Regulatory balancing accounts and other – net	**79**	289
	510	(393)
Total	**$ 234**	$ 66

The regulatory asset related to the rate reduction notes will be recovered over the terms of those notes. The net regulatory asset related to the unamortized nuclear investment will be recovered by the end of the remaining useful lives of the nuclear assets. SCE has requested a four-year recovery period for the net regulatory asset related to its unamortized coal plant investment. CPUC approval is pending. The other regulatory assets and liabilities are being recovered through other components of electric rates.

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. PROACT accrued interest based on the interest expense for the debt issued to finance the procurement-related obligations, net of interest income on SCE's cash balance. Income tax effects on all balancing account changes are deferred.

Related Party Transactions

Certain Edison Mission Energy subsidiaries have 49% to 50% ownership in partnerships (QFs) that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. SCE's purchases from these partnerships were $754 million in 2003, $548 million in 2002 and $983 million in 2001.

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 Edison Mission Energy bears interest at LIBOR plus 0.275%; and a $75 million note receivable from Edison Capital bears interest at a 30-day commercial paper rate (4.4% at December 31, 2003).

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. 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 considered as revenue until the associated costs are incurred.

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE, because SCE is acting as an agent for these transactions. Further, amounts billed to ($1.7 billion in 2003, $1.4 billion in 2002 and $2.0 billion in 2001) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as revenue to SCE.

Stock-Based Employee Compensation

SCE has three stock-based employee compensation plans, which are described more fully in Note 7. SCE accounts for those plans using the intrinsic value method. Upon grant, no stock-based employee 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. Compensation expense recorded under the stock-compensation program was $7 million in 2003, $7 million in 2002 and $1 million in 2001. The following table illustrates the effect on net income if SCE had used the fair-value accounting method.

In millions Year ended December 31,	**2003**	2002	2001
Net income available for common stock, as reported	**$ 922**	$ 1,228	$ 2,386
Less: Additional stock-based compensation expense using the fair-value accounting method – net of tax	**2**	(2)	3
Pro forma net income available for common stock	**$ 920**	$ 1,230	$ 2,383

Supplemental Accumulated Other Comprehensive Loss Information

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

In millions December 31,	**2003**	2002
Minimum pension liability – net[1]	**$ (9)**	$ (5)
Unrealized losses on cash flow hedges – net	**(10)**	(11)
Accumulated other comprehensive loss	**$ (19)**	$ (16)

[1] The minimum pension liability is discussed in Note 7, Employee 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 $9 million (as of December 31, 2003, 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 2004. Additionally, SCE recorded a $1 million unrealized loss as of December 31, 2003 on an interest rate hedge that terminated on January 7, 2004.

Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions Year ended December 31,	**2003**	2002	2001
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 390**	$ 487	$ 455
Tax payments (receipts)	**585**	1,110	(105)
Non-cash investing and financing activities:			
Details of debt exchange:			
Retirement of senior secured credit facility	**$ (700)**	—	—
Cash paid	**500**	—	—
Short-term credit facility utilized	**$ 200**	—	—
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**	—	—
Details of senior secured credit facility transaction:			
Retirement of credit facility	—	$ (1,650)	—
Senior secured credit facility replacement	—	1,600	—
Cash paid on retirement of credit facility	—	$ (50)	—

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings in other nonoperating income. 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 4.3% for 2003, 4.2% for 2002 and 3.6% for 2001.

AFUDC – equity was $21 million in 2003, $11 million in 2002 and $7 million in 2001. AFUDC – debt was $6 million in 2003, $8 million in 2002 and $9 million in 2001.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Historically, cash payments for removal costs less salvage were charged to the accumulated provision for depreciation and decommissioning and cash collections from customers for future decommissioning were credited to accumulated provision for depreciation and decommissioning. However, as a result of recent guidance from the staff of the Securities and Exchange Commission, SCE reclassified amounts related to removal costs to regulatory liabilities in its December 31, 2003 and 2002 balance sheets. See further discussion in "New Accounting Principles" and "Regulatory Assets and Liabilities."

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

SCE's net investment in generation-related utility plant was $867 million at December 31, 2003 and $842 million at December 31, 2002.

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

Note 2. Regulatory Matters

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity purchases. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its electricity 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). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

CPUC Litigation Settlement Agreement

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all of SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 procurement plan for SCE, which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15%–17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002 CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated the CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with the CDWR contracts is included within the cap.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

In January 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. In February 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. In July 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. In August 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. On November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Mohave Generating Station and Related Proceedings

In May 2002, SCE filed an application with the CPUC to address certain issues (mainly coal and slurry-water supply issues) facing the future extended operation of Mohave, which is partly owned by SCE. Mohave obtains 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 is 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.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The 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 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 are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

For additional matters related to Mohave, see "Navajo Nation Litigation" in Note 10.

In light of all of the issues discussed above, SCE has concluded that it is probable Mohave will 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 cost was deferred and recorded as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through a balancing account mechanism presented in its May 2002 application and discussed in its supplemental testimony filed in January 2003.

Wholesale Electricity and Natural Gas Markets

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the PX/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. Under the 2001 CPUC settlement agreement, mentioned in "CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso Natural Gas Company had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its energy resource recovery account mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

Note 3. Derivative Instruments and Hedging Activities

SCE's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments, fluctuations in interest rates and energy prices, but prohibits the use of these instruments for speculative or trading purposes.

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. SCE also adopted subsequent interpretations of this standard. The standard requires derivative instruments to be recognized on the balance sheet 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. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of the hedge. For a hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's equity under the caption "accumulated other comprehensive income," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately.

SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power-purchase contracts at fair value effective January 1, 2001. The unamortized loss of $9 million (as of December 31, 2003, net of tax) on the interest rate swap will be amortized over a period ending in 2008, when the related debt matures.

In December 2003, SCE entered into an interest rate lock to hedge its exposure to changes in interest rates for $825 million of anticipated issuances of first mortgage bonds. SCE recorded a $1 million liability as of December 31, 2003, representing the fair value of the interest rate lock. The lock expired on January 7, 2004, the pricing date of $975 million of new mortgage bonds, resulting in a payment of $6 million to the counterparties due to a decline in treasury rates. This loss will be treated as a debt discount and amortized over the life of the mortgage bonds.

SCE has bilateral forward power contracts, which are considered normal purchases under accounting rules. SCE is exposed to credit loss in the event of nonperformance by the counterparties to its bilateral forward contracts, but does not expect the counterparties to fail to meet their obligations. The counterparties are required to post collateral depending on the creditworthiness of each counterparty.

In October and November 2001, SCE purchased $209 million of call options that mitigated its exposure to increases in natural gas prices during 2002 and 2003. This amount was recovered through a balancing account mechanism. Amounts paid to QFs for energy are based on natural gas prices. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings. In fourth quarter 2003, SCE purchased $4 million of call options to hedge some gas price exposure for 2004.

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. A portion of these contracts is not eligible for the normal purchases and sales exception under accounting rules, and the fair value is recorded on the balance sheet. Any fair value changes for these QF contracts are offset through a regulatory mechanism; therefore, fair value changes do not affect earnings.

Fair values of financial instruments are:

In millions December 31,	2003	2002
Financial assets:		
Decommissioning trusts	**$ 2,530**	$ 2,210
Commodity price derivatives:		
Natural gas	**3**	77
Financial liabilities:		
Interest rate hedges	**1**	—
DOE decommissioning and decontamination fees	**18**	22
QF power contracts	**32**	70
Long-term debt	**4,446**	4,543
Long-term debt due within one year	**377**	1,722
Preferred stock subject to mandatory redemption	**139**	129
Preferred stock to be redeemed within one year	**9**	8

Financial assets' fair values are based on quoted market prices for decommissioning trusts and financial models for commodity price derivatives.

Financial liabilities' fair values are based on: discounted future cash flows for United States Department of Energy (DOE) decommissioning and decontamination fees; financial models for QF power contracts; and brokers' quotes for interest rate hedges, long-term debt and preferred stock.

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

Note 4. Liabilities

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. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arrangements with securities dealers to remarket or purchase them if necessary. As a result of investors' concerns regarding SCE's liquidity difficulties and overall financial condition, SCE had to repurchase $550 million of pollution-control bonds in December 2000 and early 2001 that could not be remarketed in accordance with their terms. On March 1, 2002, SCE remarketed $196 million of the pollution-control bonds that SCE had repurchased in late 2000.

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

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,	2003	2002
First and refunding mortgage bonds:		
2004 – 2026 (5.875% to 8.00% and variable)	**$1,816**	$2,275
Rate reduction notes:		
2004 – 2007 (6.38% to 6.42%)	**985**	1,232
Pollution-control bonds:		
2005 – 2040 (5.125% to 7.2% and variable)	**1,216**	1,216
Bonds repurchased	**(354)**	(354)
Debentures and notes:		
2006 – 2053 (5.06% to 7.625% and variable)	**758**	1,750
Subordinated debentures:		
2044 (8.375%)	**100**	100
Long-term debt due within one year	**(371)**	(1,671)
Unamortized debt discount – net	**(29)**	(23)
Total	**$4,121**	$4,525

Note: rates and terms as of December 31, 2003

Long-term debt maturities and sinking-fund requirements for the next five years are: 2004 – $371 million; 2005 – $442 million; 2006 – $446 million; 2007 – $1.2 billion; and 2008 – zero.

At December 31, 2003, SCE had $200 million in outstanding short-term debt as part of a credit line with a limit of $700 million. The weighted-average rate for this short-term debt was 2.83%.

At December 31, 2002, SCE had no short-term debt, no available short-term credit lines and had fully drawn a long-term credit line of $300 million.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $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. The proceeds were used to redeem $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 March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

In compliance with a new accounting standard, effective July 1, 2003, SCE reclassified its preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. This item was previously classified between liabilities and equity.

SCE has 12 million authorized shares of preferred stock subject to mandatory redemption. Mandatorily redeemable preferred stock is subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid, if any, are charged to expense.

Preferred stock redemption requirements for the next five years are: 2004 – $9 million; 2005 – $9 million; 2006 – $9 million; 2007 – $69 million; and 2008 – $54 million.

Cumulative preferred stock subject to mandatory redemption is:

Dollars in millions, except per-share amounts December 31,	December 31, 2003 Shares Outstanding	December 31, 2003 Redemption Price	**2003**	2002
$100 par value:				
6.05% Series	693,800	$ 100.00	**$ 69**	$ 75
7.23	807,000	100.00	**81**	81
Preferred stock to be redeemed within one year			**(9)**	(9)
Total			**$141**	$147

In 2001, SCE did not redeem any preferred stock. In 2002, SCE redeemed 1,000,000 shares of 6.45% Series preferred stock. In 2003, SCE redeemed 56,200 shares of 6.05% Series preferred stock. SCE did not issue any preferred stock in the last three years.

The 7.23% Series preferred stock 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 is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2002 or 2003. At December 31, 2003, SCE had 93,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

Note 5. Preferred Stock Not Subject to Mandatory Redemption

SCE's authorized shares are: $25 cumulative preferred – 24 million and preference – 50 million. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity.

Cumulative preferred stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		2003	2002
	December 31, 2003			
	Shares Outstanding	Redemption Price		
$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
Total			**$129**	$129

Note 6. 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 the net accumulated deferred income tax liability are:

In millions	December 31,	2003	2002
Deferred tax assets:			
Accrued charges		**$ 334**	$ 416
Investment tax credits		**68**	73
Property-related		**243**	178
Regulatory balancing accounts		**144**	5,365
Unrealized gains or losses		**365**	274
Decommissioning		**166**	—
Other		**199**	212
Total		**$1,519**	$ 6,518
Deferred tax liabilities:			
Property-related		**$2,762**	$ 2,847
Capitalized software costs		**160**	204
Regulatory balancing accounts		**360**	5,606
Unrealized gains and losses		**262**	171
Decommissioning		**30**	—
Other		**163**	306
Total		**$3,737**	$ 9,134
Accumulated deferred income taxes – net		**$2,218**	$ 2,616
Classification of accumulated deferred income taxes:			
Included in deferred credits		**$2,726**	$ 2,915
Included in current assets		**508**	299

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

In millions Year ended December 31,	**2003**	2002	2001
Current:			
Federal	**$ 408**	$ 990	$ 240
State	**174**	273	29
	582	1,263	269
Deferred:			
Federal	**(134)**	(504)	1,052
State	**(60)**	(117)	337
	(194)	(621)	1,389
Total	**$ 388**	$ 642	$1,658

The federal statutory income tax rate is reconciled to the effective tax rate below:

Year ended December 31,	**2003**	2002	2001
Federal statutory rate	**35.0%**	35.0%	35.0%
Favorable resolution of audit	**(2.8)**	(1.9)	—
Resolution of FERC rate case	**(5.9)**	—	—
Property-related and other	**(1.8)**	(4.5)	—
State tax – net of federal deduction	**6.0**	5.4	5.8
Effective tax rate	**30.5%**	34.0%	40.8%

The composite federal and state statutory income tax rate was 40.551% for all years presented. The lower effective tax rate of 34% realized in 2002 was primarily due to reestablishing a tax-related regulatory asset due to implementation of the utility-retained generation decision and recording the benefit of favorable settlement of Internal Revenue Service (IRS) audits.

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 10.

Note 7. Employee 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 $33 million in 2003, $30 million in 2002 and $29 million in 2001.

Pension Plan

Defined benefit pension plans (the non-executive plan has a cash balance feature) cover employees meeting minimum service requirements. SCE recognizes pension expense for its non-executive plan as calculated by the actuarial method used for ratemaking.

At December 31, 2003 and December 31, 2002, 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 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 $33 million for the year ended December 31, 2004. 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.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2003**	2002
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 2,550**	$ 2,371
Service cost	**79**	69
Interest cost	**162**	158
Actuarial loss	**148**	90
Benefits paid	**(130)**	(138)
Projected benefit obligation at end of year	**$ 2,809**	$ 2,550
Accumulated benefit obligation at end of year	**$ 2,424**	$ 2,177
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 2,281**	$ 2,723
Actual return on plan assets	**594**	(311)
Employer contributions	**34**	7
Benefits paid	**(130)**	(138)
Fair value of plan assets at end of year	**$ 2,779**	$ 2,281
Funded status	**$ (30)**	$ (269)
Unrecognized net loss	**111**	394
Unrecognized transition obligation	**6**	11
Unrecognized prior service cost	**84**	98
Recorded asset	**$ 171**	$ 234
Additional detail of amounts recognized in balance sheets:		
Intangible asset	**$ 3**	$ 3
Accumulated other comprehensive income	**(16)**	(9)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 78**	$ 55
Accumulated benefit obligation	**60**	41
Fair value of plan assets	—	—
Weighted-average assumptions at end of year:		
Discount rate	**6.0%**	6.5%
Rate of compensation increase	**5.0%**	5.0%

Expense components are:

In millions Year ended December 31,	2003	2002	2001
Service cost	**$ 79**	$ 69	$ 69
Interest cost	**162**	158	157
Expected return on plan assets	**(187)**	(224)	(251)
Special termination benefits	**3**	—	13
Net amortization and deferral	**34**	21	(7)
Expense under accounting standards	**91**	24	(19)
Regulatory adjustment – deferred	**(44)**	(18)	39
Total expense recognized	**$ 47**	$ 6	$ 20
Change in accumulated other comprehensive income	**$ (7)**	$ (9)	—
Weighted-average assumptions:			
Discount rate	**6.5%**	7.0%	7.25%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected return on plan assets	**8.5%**	8.5%	8.5%

Asset allocations are:

	Target for 2004	December 31, 2003	December 31, 2002
United States equity	45%	**46%**	45%
Non-United States equity	25	**26**	25
Private equity	4	**3**	3
Fixed income	26	**25**	27

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 has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense in the financial statements or this Note do not reflect the effects of the Act on SCE's plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require SCE to restate previously reported information.

The expected contributions (all by the employer) to the postretirement benefits other than pensions trust are $100 million for the year ended December 31, 2004. This amount is subject to change based on, among other things, the Act referenced above and the impact of any benefit plan amendments.

SCE uses a December 31 measurement date.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2003**	2002
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,103**	$ 1,925
Service cost	**42**	42
Interest cost	**122**	133
Amendments	**(622)**	—
Actuarial loss	**581**	82
Benefits paid	**(89)**	(79)
Benefit obligation at end of year	**$ 2,137**	$ 2,103
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,072**	$ 1,139
Actual return on plan assets	**291**	(148)
Employer contributions	**115**	160
Benefits paid	**(89)**	(79)
Fair value of plan assets at end of year	**$ 1,389**	$ 1,072
Funded status	**$ (748)**	$ (1,031)
Unrecognized net loss	**1,027**	702
Unrecognized transition obligation	**(342)**	268
Recorded asset (liability)	**$ (63)**	$ (61)
Assumed health care cost trend rates:		
Rate assumed for following year	**12.0%**	9.75%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2010**	2008
Weighted-average assumptions at end of year:		
Discount rate	**6.25%**	6.75%

Expense components are:

In millions Year ended December 31,	**2003**	2002	2001
Service cost	**$ 42**	$ 42	$ 44
Interest cost	**122**	133	129
Expected return on plan assets	**(89)**	(93)	(98)
Special termination benefits	**1**	—	2
Net amortization and deferral	**41**	37	27
Total expense	**$ 117**	$ 119	$ 104
Assumed health care cost trend rates:			
Current year	**9.75%**	10.5%	11.0%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2008**	2008	2008
Weighted-average assumptions:			
Discount rate	**6.4%**	7.25%	7.5%
Expected return on plan assets	**8.2%**	8.2%	8.2%

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $305 million and annual aggregate service and interest costs by $27 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $248 million and annual aggregate service and interest costs by $22 million.

Asset allocations are:

	Target for 2004	December 31, 2003	December 31, 2002
United States equity	64%	**64%**	64%
Non-United States equity	16	**13**	13
Fixed income	20	**23**	23

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. SCE employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is controlled through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. SCE also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States 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 Employee Compensation

In 1998, Edison International shareholders approved the Edison International Equity Compensation Plan, replacing the long-term incentive compensation program that had been adopted by Edison International shareholders in 1992. The 1998 plan authorizes a limited annual number of Edison International common shares that may be issued in accordance with plan awards. The annual authorization is cumulative, allowing subsequent issuance of previously unutilized awards. In May 2000, the Edison International Board of Directors adopted an additional plan, the 2000 Equity Plan, under which stock options, including the special options discussed below, may be awarded.

Under the 1992, 1998 and 2000 plans, options on 8.6 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

Each option may be exercised to purchase one share of Edison International common stock and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Options generally expire 10 years after date of grant and vest over a period of up to five years.

Edison International stock options awarded prior to 2000 include a dividend equivalent feature. Dividend equivalents on stock options issued after 1993 and prior to 2000 are accrued to the extent dividends are declared on Edison International common stock and are subject to reduction unless certain performance criteria are met. Only a portion of the 1999 Edison International stock option awards include a dividend equivalent feature. The 2003 options include a dividend equivalent feature for the first five years of the option term. Dividend equivalents accumulate without interest.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, in 25% increments beginning in May 2002. Earlier options had a three-year vesting period with one-third of the total award vesting annually. If an option holder retires, dies, is terminated by the company, or is terminated while permanently and totally disabled (qualifying event) during the vesting period, the unvested options will vest on a pro rata basis.

Unvested options of any person who has served in the past on the SCE management committee (which was dissolved in 1993) will vest and be exercisable upon a qualifying event. If a qualifying event occurs, the vested options may continue to be exercised within their original terms by the recipient or beneficiary except that in the case of termination by the company where the option holder is not eligible for retirement, vested options are forfeited unless exercised within one year of termination date. If an option holder is terminated other than by a qualifying event, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

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

December 31,	**2003**	2002	2001
Expected life	**10 years**	7 years – 10 years	7 years – 10 years
Risk-free interest rate	**3.8% – 4.5%**	4.7% – 6.1%	4.7% – 6.1%
Expected dividend yield	**1.8%**	1.8%	3.3%
Expected volatility	**44% – 53%**	18% – 54%	17% – 52%

The expected dividend yield above is computed using an average of the previous 12 quarters. The expected volatility above is computed on a historical 36-month basis.

The application of fair-value accounting to calculate the pro forma disclosures is not an indication of future income statement effects. The pro forma disclosures do not reflect the effect of fair-value accounting on stock-based compensation awards granted prior to 1995.

A summary of the status of Edison International stock options granted to SCE employees is as follows:

			Weighted-Average		
	Share Options	**Exercise Price**	**Exercise Price**	**Fair Value At Grant**	**Remaining Life**
Outstanding, Dec. 31, 2000	10,770,629	$14.56–$29.25	$22.56		8 years
Granted	324,934	$ 9.15–$15.92	$12.64	$4.51	
Expired	(8,400)	$18.75–$19.35	$19.10		
Forfeited	(5,830,582)	$15.41–$28.94	$20.99		
Exercised	—	—	—		
Outstanding, Dec. 31, 2001	5,256,581	$ 9.15–$29.25	$23.70		6 years
Granted	1,769,017	$ 8.90–$18.73	$18.54	$7.86	
Expired	(138,899)	$14.07–$28.94	$24.88		
Forfeited	(73,651)	$14.07–$28.13	$21.04		
Exercised	(2,250)	$14.07–$15.94	$15.26		
Outstanding, Dec. 31, 2002	6,810,798	$ 8.90–$29.25	$22.37		6 years
Granted	2,076,070	$11.88–$19.80	$12.41	$7.34	
Expired	(115,612)	$14.06–$29.25	$22.98		
Forfeited	(59,473)	$12.29–$18.73	$15.34		
Exercised	(156,697)	$11.35–$20.19	$18.71		
Outstanding, Dec. 31, 2003	8,555,086	$ 8.90–$28.94	$20.06		6 years

The number of options exercisable and their weighted-average exercise prices at December 31, 2003, 2002 and 2001 were 4,845,967 at $24.06, 4,160,675 at $24.23 and 3,699,622 at $23.92, respectively.

For the years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. Performance shares were awarded in January 2001, January 2002 and January 2003. The performance shares vest December 31, 2003, December 31, 2004 and December 31, 2005, respectively, and are paid out half in shares of Edison International common stock and half in cash. The number of shares that will be paid out from the 2002 and 2003 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specified group of peer companies. The 2001 performance share values are accrued ratably over a three-year performance period. The 2002 and 2003 performance shares will be valued based on Edison International's stock performance relative to the stock performance of other such entities.

In March 2001, deferred stock units were awarded as part of a retention program. These vested and were paid on March 12, 2003 in shares of Edison International common stock.

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units. The exchange ratio was based on the Black-Scholes value of the options and the stock price at the time the offer was extended. The exchange took place in November 2001; the options that participants elected to exchange were cancelled, and deferred stock units were issued. Approximately three options were cancelled for each deferred stock unit issued. Twenty-five percent of the deferred stock units will vest and be paid in Edison International common stock per year over four years; the first and second vesting dates were in November 2002 and November 2003, respectively. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life – 8 to 9 years; risk-free interest rate – 5.1%; expected volatility – 52%.

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

Note 8. 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.

The investment in each project as of December 31, 2003 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 45	$ 11	60%
Pacific Intertie	257	80	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	488	384	48
Mohave (coal)[1]	347	257	56
Palo Verde (nuclear)[2]	1,657	1,460	16
San Onofre (nuclear)[2]	4,297	3,923	75
Total	$ 7,091	$ 6,115	

[1] A portion is included in regulatory assets on the balance sheet. See Note 1.
[2] Included in regulatory assets on the balance sheet.

Note 9. Commitments

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates. Operating lease expense was $15 million in 2003, $16 million in 2002 and $19 million in 2001.

Estimated remaining commitments for noncancelable leases at December 31, 2003 are:

Year ended December 31,	In millions
2004	$ 13
2005	10
2006	7
2007	6
2008	4
Thereafter	8
Total	$ 48

Nuclear Decommissioning

Effective January 1, 2003, SCE adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal ARO in the period in which it is incurred. At that time, SCE adjusted its nuclear decommissioning obligation, increased its unamortized nuclear investment for a new ARO asset, and recorded a regulatory liability to defer the impact on earnings of the change in accounting principle (see further details in "New Accounting Principles" in Note 1). The fair value of decommissioning SCE's nuclear power facilities is $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 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 in the near term. SCE estimates that it will spend approximately $11.4 billion through 2049 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 0.9% to 10.0% (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 3.7% to 6.5%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($177 million at December 31, 2003). Total expenditures for the decommissioning of San Onofre Unit 1 were $317 million through December 31, 2003.

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 expire in 2022 for San Onofre Units 2 and 3, and in 2024, 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, and has historically recorded these amounts in accumulated provision for depreciation and decommissioning. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation and decommissioning for nuclear decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. Upon implementation of the new accounting standard for AROs, SCE reversed the decommissioning amounts collected for assets legally required to be removed and recorded the fair value of this ARO (included in the deferred credits and other liabilities section of the consolidated balance sheet). The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003.

Decommissioning expense under the rate-making method was $118 million in 2003, $73 million in 2002 and $96 million in 2001. The ARO for decommissioning SCE's active nuclear facilities was $1.9 billion at December 31, 2003 and $1.8 billion at December 31, 2002.

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,	2003	2002
Municipal bonds	2004 – 2041		**$ 702**	$ 486
Stock	–		**1,324**	1,085
United States government issues	2004 – 2033		**363**	264
Corporate bonds	2004 – 2038		**91**	270
Short-term	2004		**50**	105
Total			**$ 2,530**	$2,210

Note: Maturity dates as of December 31, 2003

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (loss) were $93 million in 2003, $(25) million in 2002 and $13 million in 2001. Proceeds from sales of securities (which are reinvested) were $2.2 billion in 2003, $3.8 billion in 2002 and $3.9 billion in 2001. Gross unrealized holding gains were $677 million and $443 million at December 31, 2003 and 2002, respectively. There were no unrealized holding losses for the years presented. 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. Certain SCE gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered.

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. 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 balance sheets.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $139 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power purchase contracts (approximately $28 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2004 through 2008 are estimated below:

In millions	2004	2005	2006	2007	2008
Fuel supply contract payments	$ 182	$ 126	$ 58	$ 66	$ 51
Purchased-power capacity payments	682	663	637	637	444

Note 10. 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.

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by IRS in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for SCE's cash balance pension plan does not meet the standard set forth in the federal district court's July 31, 2003 decision. SCE cannot predict with certainty the effect of the two IBM decisions on SCE's cash balance pension plan.

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 26 identified sites is $92 million. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in SCE's recorded estimated minimum environmental liability. 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 $238 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $34 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates;

shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $71 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 $13 million to $25 million. Recorded costs for 2003 were $14 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

In August 2002, Edison International received a notice from the IRS asserting deficiencies in federal corporate income taxes for its 1994 to 1996 tax years. Included in these amounts are deficiencies asserted against SCE. The vast majority of SCE's tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would benefit it as future tax deductions. SCE believes that it has meritorious legal defenses to deficiencies asserted against it and believes that the ultimate outcome of this matter will not result in a material impact on its results of operations or financial position.

Investigation 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 reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

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. 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.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the 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 analysis, on April 28, 2003, SCE filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 2003 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. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 Court of Appeals decision. Both petitions were denied on March 9, 2004.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $10.9 billion. SCE and other owners of the San Onofre and Palo Verde Nuclear Generating Stations 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 maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than

$10 million per reactor may be charged in any one year for each incident. 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 $20 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. The United States Congress has extended the expiration date of the applicable law until December 31, 2004.

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 $38 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE has the obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. However, the DOE did not meet its obligation. 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, including 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 Federal Court of Claims seeking damages for DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 1, 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation. Movement of Unit 1 spent fuel from the Unit 3 spent fuel pool to the independent spent fuel storage installation was completed in late 2003. Movement of Unit 1 spent fuel from the Unit 1 spent fuel pool to the independent spent fuel storage installation is scheduled to be completed by late 2004 and from the Unit 2 spent fuel pool to the independent spent fuel storage installation by late 2005. With these moves, there will be 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 2006.

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 11. Mountainview Acquisition

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new power plant currently being developed in Redlands, California. This acquisition requires regulatory approval from both the CPUC and the FERC. On December 18, 2003, the CPUC approved SCE's application proposing a power-purchase agreement between SCE and Mountainview Power Company LLC. On February 25, 2004, the FERC granted conditional approval of the power-purchase agreement. On February 28, 2004, SCE exercised its option to purchase Mountainview. The purchase is expected to close in March 2004. SCE will recommence full construction of the project once the purchase closes.

Note 12. Discontinued Operations

On July 10, 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. Due to immateriality, the results of this unit for prior years have not been restated and are reflected as part of continuing operations.

For 2003, revenue from discontinued operations was $20 million and pre-tax income was $82 million. As of December 31, 2002, assets of discontinued operations were $62 million.

Quarterly Financial Data (Unaudited)

	2003					2002				
In millions	**Total**	**Fourth**	**Third**	**Second**	**First**	**Total**	**Fourth**	**Third**	**Second**	**First**
Operating revenue	**$8,854**	**$1,859**	**$2,794**	**$2,386**	**$1,815**	$8,706	$1,952	$2,714	$2,133	$1,907
Operating income	**1,596**	**301**	**613**	**418**	**264**	2,127	264	452	1,107	304
Net income	**932**	**223**	**375**	**229**	**105**	1,247	157	238	700	152
Net income available for common stock	**922**	**222**	**374**	**225**	**101**	1,228	153	234	695	146
Common dividends declared	**945**	**945**	—	—	—	—	—	—	—	—

Selected Financial and Operating Data: 1999 – 2003					Southern California Edison Company
Dollars in millions	**2003**	2002	2001	2000	1999
Income statement data:					
Operating revenue	**$ 8,854**	$ 8,706	$ 8,126	$ 7,870	$ 7,548
Operating expenses	**7,258**	6,579	3,509	10,529	6,242
Purchased-power expenses	**2,786**	2,016	3,770	4,687	3,190
Income tax (benefit)	**388**	642	1,658	(1,022)	438
Provisions for regulatory adjustment clauses – net	**1,138**	1,502	(3,028)	2,301	(763)
Interest expense – net of amounts capitalized	**457**	584	785	572	483
Net income (loss)	**932**	1,247	2,408	(2,028)	509
Net income (loss) available for common stock	**922**	1,228	2,386	(2,050)	484
Ratio of earnings to fixed charges	**3.81**	4.21	6.15	*	2.94
*less than 1.00					
Balance sheet data:					
Assets	**$ 18,466**	$ 18,637	$ 22,453	$ 15,966	$ 17,657
Gross utility plant	**16,973**	16,232	15,982	15,653	14,851
Accumulated provision for depreciation and decommissioning	**4,386**	4,057	7,969	7,834	7,520
Short-term debt	**200**	—	2,127	1,451	796
Common shareholder's equity	**4,355**	4,384	3,146	780	3,133
Preferred stock:					
Not subject to mandatory redemption	**129**	129	129	129	129
Subject to mandatory redemption	**141**	147	151	256	256
Long-term debt	**4,121**	4,525	4,739	5,631	5,137
Capital structure:					
Common shareholder's equity	**49.8%**	47.7%	38.5%	11.5%	36.2%
Preferred stock:					
Not subject to mandatory redemption	**1.5%**	1.4%	1.6%	1.9%	1.5%
Subject to mandatory redemption	**1.6%**	1.6%	1.9%	3.8%	2.9%
Long-term debt	**47.1%**	49.3%	58.0%	82.8%	59.4%
Operating data:					
Peak demand in megawatts (MW)	**20,136**	18,821	17,890	19,757	19,122
Generation capacity at peak (MW)	**9,861**	9,767	9,802	9,886	10,431
Kilowatt-hour deliveries (in millions)	**93,826**	79,693	78,524	84,430	78,602
Total energy requirement (kWh) (in millions)	**77,159**	71,663	83,495	82,503	78,752
Energy mix:					
Thermal	**37.9%**	40.2%	32.5%	36.0%	35.5%
Hydro	**5.2%**	5.0%	3.6%	5.4%	5.6%
Purchased power and other sources	**56.9%**	54.8%	63.9%	58.6%	58.9%
Customers (in millions)	**4.60**	4.53	4.47	4.42	4.36
Full-time employees	**12,698**	12,113	11,663	12,593	13,040

BOARD OF DIRECTORS

John E. Bryson [3]
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 financial investment nonutility
subsidiary of Edison International)
A director from 1990 – 1999;
2003 to present

Alan J. Fohrer [3]
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 [2,5]
Chairman and Chief Executive Officer,
KB Home (homebuilding)
Los Angeles, California
A director since 2002

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

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

James M. Rosser [2,3,5]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1985

Richard T. Schlosberg, III [1,5]
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]
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

Daniel M. Tellep [1,4] *
Retired Chairman of the Board,
Lockheed Martin Corporation
(aerospace industry)
Saratoga, California
A director since 1992

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

* Retiring May 20, 2004

MANAGEMENT TEAM

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President, Generation

Pamela A. Bass
Senior Vice President, Customer Service

John R. Fielder
Senior Vice President, Regulatory Policy and Affairs

Stephen E. Pickett
Senior Vice President and General Counsel

Richard M. Rosenblum
Senior Vice President, Transmission and Distribution

W. James Scilacci
Senior Vice President and Chief Financial Officer

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

Emiko Banfield
Vice President, Shared Services

Robert C. Boada
Vice President and Treasurer

William L. Bryan
Vice President, Major Customer Division

Jodi M. Collins
Vice President, Information Technology

Diane L. Featherstone
Vice President and General Auditor

Bruce C. Foster
Vice President, Regulatory Operations

Polly L. Gault
Vice President, Public Affairs, Washington, D.C.

A. Larry Grant
Vice President, Power Delivery

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

Harry B. Hutchison
Vice President, Customer Service Operations

James A. Kelly
Vice President, Engineering and Technical Services

Russ W. Krieger
Vice President, Power Production

Thomas M. Noonan
Vice President and Controller

Dwight E. Nunn
Vice President, Nuclear Engineering and Technical Services

Barbara J. Parsky
Vice President, Corporate Communications

Pedro J. Pizarro
Vice President, Power Procurement, and General Manager, Edison Carrier Solutions

Frank J. Quevedo
Vice President, Equal Opportunity

Anthony L. Smith
Vice President, Tax

Joseph J. Wambold
Vice President, Nuclear Generation

Beverly P. Ryder
Corporate Secretary

ANNUAL MEETING

The annual meeting of shareholders will be held on Thursday, May 20, 2004, at 10:00 a.m., Pacific Daylight Time, at the Hyatt Regency Long Beach, 200 South Pine Avenue, Long Beach, California 90802.

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 LISTING AND TRADING INFORMATION

Preferred Stock

SCE's 4.08%, 4.24%, 4.32% and 4.78% Series of cumulative preferred stock are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05% and 7.23% Series of the $100 cumulative preferred stock are not listed and are traded over-the-counter.

TRANSFER AGENT AND REGISTRAR

Wells Fargo Bank, N.A., which maintains shareholder records, is the transfer agent and registrar for SCE's preferred stocks. 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

Email

stocktransfer@wellsfargo.com

Web Address

www.edisoninvestor.com

Online account information:

www.shareowneronline.com

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EDISON

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