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SOUTHERN CALIFORNIA EDISON CO. 2004 Annual Report

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Southern California Edison Company

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

SCE, a 119-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 description of how SCE earns revenue and income and a brief review of the company's consolidated earnings for 2004, and a summary of issues for 2004 and 2005. 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) Dispositions and Discontinued Operations; (8) Acquisition; (9) Critical Accounting Policies and Estimates; (10) New Accounting Principles; and (11) Commitments.

MANAGEMENT OVERVIEW

Background

SCE is an investor-owned utility company providing electricity to retail customers in central, coastal and southern California. SCE is regulated by the California Public Utilities Commission (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.

<u>Base Rates</u>: 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, transmission and distribution plant (or rate base). Base rates provide for recovery of operations and maintenance costs, capital-related carrying costs (depreciation, taxes and interest) and a return or profit, on a forecast basis. Base rates related to SCE's generation and distribution functions are authorized by the CPUC through a general rate case (GRC). In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement. After a review process and hearings, the CPUC sets an annual revenue requirement by multiplying an authorized rate of return, determined in annual cost of capital proceedings (as discussed below), by rate base, then adding to this amount the adopted operation and maintenance costs and capital-related carrying costs. Adjustments to the revenue requirement for the remaining years of a typical three-year GRC cycle are requested from the CPUC based on criteria established in a GRC proceeding for escalation in operation and maintenance costs, changes in capital-related costs and the expected number of nuclear refueling outages. See "Regulatory Matters—Transmission and Distribution—2003 General Rate Case Proceeding" for SCE's current annual revenue requirement. Variations in generation and distribution revenue arising from the difference between forecast and actual electricity sales are recorded in balancing accounts for future recovery or refund, and do not impact SCE's operating profit, while differences between forecast and actual 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 an annual cost of capital proceeding. The rate of return is a weighted average of the return on common equity and cost of long-term debt and preferred stock.

Current CPUC ratemaking also provides for performance incentives or penalties for differences between actual results and GRC-determined standards of reliability 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 collected prior to a final FERC decision is subject to refund. SCE's current authorized annual revenue requirement of approximately $260 million recovers the costs associated with its transmission function and earns a reasonable return on its $1.1 billion transmission rate base.

<u>Cost-Recovery Rates</u>: Revenue requirements to recover SCE's costs of fuel, purchased power, demand-side management programs, nuclear decommissioning costs, rate reduction debt requirements, and public purpose programs are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 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. Rates are adjusted, as necessary, to recover or refund any under- or over-collections. The majority of costs eligible for recovery are subject to CPUC reasonableness reviews, and thus could negatively impact earnings and cash flows if found to be unreasonable and disallowed.

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 in 2001, 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.

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

SCE's 2004 Consolidated Earnings

SCE's recorded earnings were $915 million in 2004, compared to $922 million in 2003. The decrease in earnings was primarily due to a decrease in operating earnings reflecting the expiration of SCE's performance incentive mechanisms for San Onofre Nuclear Generating Station (San Onofre), partially offset by higher revenue net of operating expenses and the net benefits from the resolution of several regulatory and prior years' tax issues. For a detailed review and analysis of the consolidated results of operations and historical cash flows, see "Results of Operations and Historical Cash Flow Analysis" section.

SCE 2004 Issues – Overview

In 2004, SCE's primary management focus was on numerous business issues that could have materially affected SCE's earnings, cash flow, or business risk. The following is a brief review of SCE's performance on its 2004 key business issues.

- In July 2004, the CPUC issued a final decision in SCE's 2003 GRC, authorizing an annual increase of $73 million in base rates and providing for base rate adjustments in 2004 and 2005. The CPUC's decision is retroactive to May 22, 2003. In the decision, the CPUC approved nearly all of SCE's requested capital spending. Moreover, the CPUC adopted a mechanism to adjust base rates based on SCE's forecast of capital expenditures and operating and maintenance escalation for 2004 and 2005.

- All of SCE's major business functions (distribution, transmission and generation) had significant demands for capital investment. During 2004, SCE's new account additions totaled 68,400. In 2004, SCE spent approximately $2.0 billion in capital expenditures, including $285 million related to the acquisition of the Mountainview project. At year-end 2004, SCE's rate base was $9.4 billion. With the 2003 GRC decision, SCE substantially increased the replacement of distribution poles, transformers and other infrastructure during 2004. This is part of a long-term effort known as the Infrastructure Replacement Program, which is designed to step up the level of infrastructure replacement to maintain existing levels of system reliability. A significant portion of SCE's existing distribution infrastructure was installed during the post-World War II population boom.

- During 2004, SCE took major steps in implementation of its transmission expansion plans to meet customer load-growth requirements, including:

    - Completed the reconstruction of the Sylmar Converter Station. This $120 million project (SCE's share is $60 million), allows 3,100 megawatt (MW) of power to flow to southern California;

    - Obtained regulatory approval to spend $125 million to upgrade SCE's Devers/Palo Verde 1 transmission line. This project will add 505 MW by 2006;

    - Filed an application with the California Independent System Operator (ISO) for approval to construct the $680 million Devers/Palo Verde 2 transmission line. This application was approved on February 24, 2005. If approved by other regulatory agencies, the line would add 1,200 MW of power to southern California by 2009;

    - Filed an application with the CPUC to construct the $224 million Antelope Area Transmission project. This project will expand SCE's transmission system, allowing additional suppliers of wind energy from the Tehachapi wind region (near Mohave, California).

- Generation capital spending increased dramatically in 2004. SCE made significant progress in the construction of the 1,054 MW Mountainview project. At year-end 2004, the project was about 50% completed and was on schedule to complete construction by the end of the first quarter 2006. At SCE's San Onofre site, security upgrades driven by the Nuclear Regulatory Commission required $54 million of capital spending, slightly above what had been budgeted for 2004. Also during 2004, San Onofre Unit 3 experienced an extended outage due to the replacement of the pressurizer heater sleeves as a result of degradation. This outage reduced the 2004 capacity factor of Unit 3 to 74%.

- In February 2004, SCE filed an application with the CPUC to replace the San Onofre steam generators and to adopt the estimated reasonable replacement cost of $510 million (SCE's share). In September 2004, SCE signed a contract for the fabrication of new steam generators. See "Regulatory Matters—Generation and Power Procurement—San Onofre Nuclear Generating Station."

- During 2004, SCE and its co-owners of the Mohave Generating Station (Mohave), a 1,580 MW coal-fired plant (SCE has a 56% ownership), continued negotiations to find a reasonable path to continue Mohave operations beyond 2005. Under the terms of a consent decree, the Mohave owners must install certain pollution-control equipment in order to operate beyond 2005. Before the investment can be evaluated by the co-owners, future coal and water supply issues must be resolved. See "Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings."

- SCE has numerous concerns associated with providing power for its bundled service customers. As discussed in the "—Background" section, SCE recovers only reasonable costs associated with procuring power for its customers, with no markup or profit. Because of the substantial costs associated with power procurement, SCE spends considerable management focus to ensure that both customer and shareholder risks are reasonably protected. During 2004, SCE supported Assembly Bill 2006, which would have created a fairer and more durable regulatory framework associated with generation investments and purchased-power costs. Although the bill was passed by the State Legislature, it was vetoed by the Governor of California. However, in the CPUC's decisions affecting power procurement, meaningful progress was made towards a fairer regulatory framework supporting power procurement. In particular, the CPUC:

    - recognized the financial implications of debt equivalence (the fixed financial obligations resulting from long-term power-purchase contracts) when evaluating competitive bids on power-purchase contracts, and also provided a mechanism to begin mitigating its impact;

    - extended the power procurement trigger mechanism, allowing for adjustment in procurement rates should currently authorized rates cause revenue to exceed or under run actual costs by 5% of SCE prior year's procurement costs (see "Market Risk Exposures—Commodity Price Risk"); and

    - provided stranded cost recovery for long-term power procurement arrangements.

- SCE has identified that resource adequacy requirements, anticipated closure of Mohave at the end of 2005, reduction in deliveries of CDWR allocated-contract power, expiration of qualifying facilities (QF) contracts, and peak-load growth of 1.5% to 2% per year would require SCE to seek substantial amounts of incremental capacity. During 2004, SCE conducted a number of competitive solicitations to meet its resource requirements, as specified by regulatory rules. Based on the results of SCE's 2004 solicitations, SCE expects to meet its 2005 requirements and has significantly reduced its estimate of the amount of resources needed to meet the requirements for 2006 and 2007. SCE also is seeking additional suppliers of renewable power to attain CPUC-mandated levels. At year-end 2004, SCE obtained approximately 18% of its power supplies from renewable resources. SCE must achieve 20% by 2010, or could be subject to penalties.

- During 2004, SCE remained concerned about high customer rates, which were a contributing factor that led to the deregulation of the electric services industry during the mid-1990s. At the beginning of 2004, SCE's system average rate for bundled service customers was 12.5¢-per-kilowatt-hour (kWh). As of December 31, 2004, that rate was 12.2¢-per-kWh. On April 14, 2005, SCE expects to implement new rates that will result in a system average of 13.0¢-per-kWh. The expected rate increase is due to higher gas prices and increased power purchases resulting from resource adequacy requirements and a reduction in CDWR power deliveries. On a cents-per-kWh basis, SCE's average rate is above the national average, but similar to other investor-owned electric utilities in California.

- During 2004, a new issue emerged that affected SCE's performance. SCE found that a number of employees had falsified customer data which was reported to the CPUC in support of certain performance incentive rewards. Upon further investigation, SCE also discovered that it had not appropriately collected or maintained data on employee safety which is also tied to a CPUC performance incentive reward. SCE reported its findings to the CPUC, terminated and disciplined certain employees, and committed to the CPUC to either refund or not seek any performance incentives in the affected areas. SCE recorded a $29 million pre-tax earnings charge in 2004 to account for the anticipated refund of the previously received performance incentive rewards. SCE is committed to implementing programs that greatly strengthen the ethics and compliance programs and culture at SCE.

SCE 2005 Issues – Overview

This overview discusses key business issues facing SCE in 2005. It is not intended to be an exhaustive discussion, but a summary of current or developing corporate issues. It includes items that could materially affect SCE's earnings, cash flow, or business risk. The issues discussed in this overview are described in more detail in the remainder of this "Southern California Edison Company" section.

In October 2004, Edison International adopted a comprehensive multi-year strategic plan. For the remaining years, 2005–2009, the plan provides for SCE to incur $9.4 billion in capital expenditures which would increase SCE's rate base from $9.4 billion at year-end 2004 to $14.2 billion by year-end 2009. To achieve this projected growth, SCE must have all regulatory approvals to spend the forecasted capital, and the people, processes, and systems to implement the authorized capital expenditures. Pursuant to the plan, SCE expects to spend $1.6 billion on capital projects in 2005 and expects to have a rate base of $10.2 billion at year-end 2005. Through the 2003 GRC decision, ratemaking for SCE's 2005 capital expenditures already is in place. Significant investments in 2005 are expected to include:

- $200 million related to transmission projects.

- $1.1 billion related to distribution projects.

- $300 million related to generation projects, including the completion of the construction of the Mountainview project.

In order to achieve this growth for 2005 and beyond, SCE needs to make meaningful progress on several transmission projects including:

- Devers/Palo Verde 1 transmission line upgrades.

- Rancho Vista Substation, Devers/Palo Verde 2 transmission line, and Antelope Transmission project, all of which were approved by the ISO in 2005. The CPUC approval process must now be initiated.

2005 is an important year for several generation projects. The Mountainview project will be substantially completed in 2005, with an anticipated in-service date during the first quarter of 2006. During 2005, the CPUC is expected to render a final decision on SCE's San Onofre steam generator replacement application. In addition, future ownership of San Onofre is affected by co-owners opting out of steam generator investments. This could result in SCE assuming a greater financial responsibility for steam generator replacement and increased ownership interest. See "Regulatory Matters—Generation and Power Procurement—San Onofre Nuclear Generating Station." The future of Mohave still remains uncertain. SCE will continue to seek a solution permitting extension of Mohave's operation beyond 2005 on commercially reasonable terms, or provide for its permanent shutdown. A commitment to extend Mohave's operation and the possible $1.1 billion capital expenditures (SCE's share is $605 million), is not included in SCE's capital forecast. See "Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings."

In December 2004, SCE filed an application with the CPUC for its 2006 GRC. The application requests the CPUC to increase base rates by $370 million, primarily for capital-related expenditures to accommodate customer and load growth and substantially higher operation and maintenance expenditures particularly in SCE's transmission and distribution business unit. The application also seeks base rate increases for 2007 and 2008, permitting escalation for operating expenditures and planned capital expenditures. If the schedule is maintained, a final decision is expected at year-end 2005. See "Regulatory Matters—Transmission and Distribution—2006 General Rate Case Proceeding." Adoption of the capital forecast incorporated in SCE's 2006 GRC is essential to meeting the targets incorporated in SCE's strategic plan.

In 2004, SCE commenced a broad initiative to redesign key work processes associated with capital expenditures within the transmission and distribution business unit. The initiative, known as business process integration, is designed to modify existing work processes which focus on individual business units and replace them with integrated work processes spanning the entire utility. This initiative should produce efficiency of business systems, reduction of capital requirements and streamlined business processes. SCE has incorporated expected savings from business process integration in its 2006 GRC forecast.

In 2005, SCE will continue to focus on meeting the CPUC's new minimum planning reserve margin of 15-17% above its average-year peak load. In January 2004, the CPUC adopted this minimum planning reserve margin for all load-serving entities, including SCE, which supplies power to about 85% of the retail load served by its transmission and distribution system. In October 2004, the CPUC accelerated the effective date for the minimum planning reserve margin from 2008 to 2006. SCE has met the minimum planning reserve margin for 2005. However, as power-purchase contracts expire, generating plants retire, and load grows, SCE anticipates the need to sign additional power-purchase contracts in the years ahead to meet the minimum planning reserve requirement beyond 2005. The ISO, CPUC and the California Energy Commission have identified SCE's service territory as an area in which new generation will soon be needed. SCE will continue to advocate to State officials the need for a market and regulatory framework that will support developers' efforts to obtain financing for new generation projects. Over time, a robust resource adequacy framework implemented through stable capacity markets may achieve this goal; in the interim, developers may not be able to obtain financing without long-term contracts with creditworthy load-serving entities. Long-term contracts with new generators are likely to be more costly than short-term contracts with existing generators. However, load-serving entities are not in a position to sign these more costly, long-term contracts for new generation in an environment in which their retail customers can elect another service provider. SCE will continue working with State officials to find transitional and long-term solutions to this fundamental problem that treat all load-serving entities equitably and are workable even if the State expands competitive retail markets.

LIQUIDITY

SCE's liquidity is primarily affected by under- or over-collections of procurement-related costs, collateral and mark-to-market requirements associated with power-purchase contracts, and access to capital markets or external financings. At December 31, 2004, SCE's credit and long-term senior secured issuer ratings from Standard & Poor's and Moody's Investors Service were BBB and A3, respectively. On February 16, 2005, Standard & Poor's raised SCE senior secured credit rating to BBB+ from BBB. On September 17, 2004, Moody's Investors Service assigned SCE a short-term credit rating of P2 in connection with SCE's launch of a new $700 million commercial paper program.

Standard & Poor's had previously issued SCE a short-term credit rating of A2. As of December 31, 2004, SCE had $88 million in commercial paper outstanding.

As of December 31, 2004, SCE had cash and equivalents of $122 million ($90 million relates to cash held by SCE's consolidated Variable Interest Entities (VIEs)). As of December 31, 2004, long-term debt, including current maturities of long-term debt, was $5.5 billion. As of December 31, 2004, SCE posted approximately $75 million ($65 million in cash and $10 million in letters of credit) as collateral to secure its obligations under power-purchase contracts and to transact through the 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. At December 31, 2004, SCE had a $700 million senior secured credit facility with an expiration date of December 2006. The credit facility was not utilized, except for $98 million supporting the commercial paper outstanding and the letters of credit as mentioned above. Subsequently, in February 2005, the $700 million credit facility was replaced with a $1.25 billion senior secured 5-year revolving credit facility. As of February 28, 2005, SCE's new credit facility supported $306 million of commercial paper outstanding and $10 million in letters of credit, leaving $934 million available under its credit facility.

SCE's 2005 estimated cash outflows consist of:

- Approximately $246 million of rate reduction notes that are due at various times in 2005, but which have a separate cost recovery mechanism approved by state legislation and CPUC decisions;

- Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct and replace generation assets;

- Dividend payments to SCE's parent company;

- Fuel and procurement-related costs; and

- General operating expenses.

SCE expects to meet its continuing obligations, including cash outflows for power-procurement undercollections (if incurred), through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary. Projected capital expenditures are expected to be financed through cash flows and the issuance of long-term debt and preferred stock.

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.

SCE is experiencing significant growth in actual and planned capital expenditures to replace and expand its distribution and transmission infrastructure and construct and replace generation assets. In 2004, SCE spent $2.0 billion, including the acquisition and construction of the Mountainview project. SCE expects its capital expenditures to be $1.6 billion, $1.8 billion and $1.9 billion in 2005, 2006 and 2007, respectively. In the 2003 GRC the CPUC approved nearly all of SCE's requested capital spending for the 2003 through 2005 period. SCE is seeking regulatory approval, in its 2006 GRC, to continue its infrastructure program for the 2006 through 2009 period.

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International (see "Edison International (Parent): Liquidity" for further discussion). In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2004, SCE's 13-month weighted-average common equity component of total capitalization was 50.5%. At December 31, 2004, SCE had the capacity to pay $222 million in additional dividends based on the 13-month weighted-average method. Based on recorded December 31, 2004 balances, SCE's common equity to total capitalization ratio, for rate-making purposes, was 50.4%. SCE had the capacity to pay $213 million of additional dividends to Edison International based on December 31, 2004 recorded balances. The CPUC has authorized SCE to increase the amount of preferred stock in its authorized capital structure from 5% to 9% of total capitalization. Correspondingly, SCE will use the proceeds to fund capital expenditures. The exact amount and timing of such issuances is dependent upon many factors, including market conditions.

In January 2005, SCE issued $650 million of first and refunding mortgage bonds. The issuance included $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds were used to redeem the remaining $50,000 of 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and $650 million of the $966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B).

SCE has debt covenants that require certain interest coverage, interest and preferred dividend coverage, and debt to total capitalization ratios to be met. At December 31, 2004, SCE was in compliance with these debt covenants.

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

MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, commodity prices and volume, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. However, fluctuations in commodity prices and volumes and counterparty credit losses temporarily affect cash flows, but should not affect earnings due to recovery through regulatory mechanisms. SCE uses derivative financial instruments to manage its market risks, but prohibits the use of these instruments for speculative purposes.

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 2004 and 11.4% for 2005), 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, 2004, 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, 2004, the fair market value of SCE's long-term debt was $5.6 billion. A 10% increase in market interest rates would have resulted in a $186 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 $206 million increase in the fair market value of SCE's long-term debt. At December 31, 2004, the fair market value of SCE's preferred stock subject to mandatory redemption was $140 million. A 10% increase and decrease in market interest rates would have resulted in a $2 million decrease and increase, respectively, in the fair market value of SCE's preferred stock subject to mandatory redemption.

Commodity Price Risk

In 2004, SCE's purchased-power expense was approximately 36% 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. Under a trigger mechanism, 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. The CPUC issued a decision on December 16, 2004, that keeps the trigger mechanism in effect during the term of long-term contracts, or 10 years, whichever is longer. 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 power procurement responsibilities for its customers. SCE forecasts that it will have a net-long position (generation supply exceeds expected load requirements) in the majority of hours during 2005. SCE's net-long position arises primarily from "must-take" deliveries under CDWR contracts allocated to SCE's customers. SCE has incorporated a 2005 price and volume forecast from expected sales of net-long power in its 2005 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 2006, SCE forecasts that it will have a net-short position (expected load requirements exceed generation supply) at certain times. SCE's forecast net-short position increases from year-to-year, assuming no new generation supply is added, as existing contracts expire, SCE generating plants retire, and load grows. However, the CPUC has set resource adequacy requirements which require SCE to acquire and demonstrate enough generating capacity in its portfolio for a planning reserve margin of 15–17% above its peak load as forecast for an average year (see "Regulatory Matters—Generation and Power Procurement—Generation Procurement Proceedings"). Accordingly, SCE anticipates continued generation contracting over time to maintain the minimum reserve margin. The establishment of a sufficient planning reserve margin mitigates, to some extent, several conditions that could increase SCE's net-short position, including lower utility generation due to expected or unexpected outages or plant closures, lower deliveries under third-party power contracts, or higher than anticipated demand for electricity. However, SCE's planning reserve margin may not be sufficient to supply the needs of all returning direct access customers (customers who choose to purchase power directly from an electric service provider other than SCE but then decided to return to utility service). Increased procurement costs resulting from the return of direct access customers could lead to temporary undercollections and the need to increase rates.

SCE anticipates purchasing additional capacity and/or ancillary services to meet its peak-energy requirements in 2005 and beyond if its net-short position is significantly higher than SCE's current forecast. As of December 31, 2004, SCE entered into power tolling arrangement and forward physical contracts to mitigate its exposure to energy prices in the spot market. The fair market value of the power tolling arrangements as of December 31, 2004, was a liability of $6 million. A 10% increase in energy prices would have resulted in a $49 million increase in the fair market value. A 10% decrease in energy prices would have resulted in a $37 million decrease in the fair market value. The fair market value of the forward physical contracts as of December 31, 2004, was an asset of $8 million. A 10% increase in energy prices would have resulted in a $1 million increase in the fair market value. A 10% decrease in energy prices would have resulted in a $2 million decrease in the fair market value.

SCE is also exposed to increases in natural gas prices related to its QF contracts, fuel tolling arrangements, and owned gas-fired generation, including the Mountainview project (expected to be on-line in 2006). SCE purchases power from QFs under CPUC-mandated contracts. Contract energy prices for most nonrenewable QFs are based in large part on the monthly southern California border price of natural gas. In addition to the QF contracts, SCE has power contracts in which SCE has agreed to provide the natural gas needed for generation under those power contracts, which are known as fuel tolling arrangements. SCE has an active gas fuel hedging program in place to minimize ratepayer exposure to spot market price spikes. However, movements in gas prices over time will impact SCE's gas costs and the cost of QF power which is related to natural gas prices.

As of December 31, 2004, SCE entered into gas forward transactions including options, swaps and futures, and fixed price contracts to mitigate its exposure related to the QF contracts and fuel tolling arrangements. The fair market value of the forward transactions as of December 31, 2004, was a liability of $11 million. A 10% increase in gas prices would have resulted in a $21 million increase in the fair market value. A 10% decrease in gas prices would have resulted in a $21 million decrease in the fair market value. SCE cannot predict with certainty whether in the future it will be able to hedge customer risk for other commodities on favorable terms or that the cost of such hedges will be fully recovered in rates.

SCE's gas expenses and gas hedging costs, as well as its purchased-power costs, are recovered through a balancing account known as the Energy Resource Recovery Account (ERRA). To the extent SCE conducts its power and gas procurement activities in accordance with its CPUC-authorized procurement plan, California statute (Assembly Bill 57) establishes that SCE is entitled to full cost recovery. Certain SCE activities, such as contract administration, SCE's duties as CDWR's limited agent for allocated CDWR contracts, and portfolio dispatch, are reviewed annually by the CPUC for reasonableness. The CPUC has currently established a maximum disallowance cap of $37 million for these activities.

Pursuant to CPUC decisions, SCE, as the CDWR's limited agent, performs certain services for CDWR contracts allocated to SCE by the CPUC, including arranging for natural gas supply. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through coordination with SCE, has hedged a portion of its expected natural gas requirements for the gas tolling contracts allocated to SCE. Increases in gas prices over time, however, will increase the CDWR's gas costs. California state law permits the CDWR to recover its actual costs through rates established by the CPUC. This would affect rates charged to SCE's customers, but would not affect SCE's earnings or cash flows.

Quoted market prices, if available, are used for determining the fair value of contracts, as discussed above. If quoted market prices are not available, internally maintained standardized or industry accepted models are used to determine the fair value. The models are updated with spot prices, forward prices, volatilities and interest rates from regularly published and widely distributed independent sources.

Credit Risk

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

In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC which sought full recovery of its electricity procurement costs incurred during the energy crisis. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the Procurement-Related Obligations Account (PROACT), as of August 31, 2001 (which was fully recovered by August 2003).

Energy Resource Recovery Account Proceedings

In an October 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—Background," 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.

2004 ERRA Forecast

SCE submitted an ERRA forecast application on October 3, 2003, in which it forecast a procurement-related revenue requirement for the 2004 calendar year of $2.3 billion. The CPUC issued a decision on

April 22, 2004, approving SCE's 2004 forecast revenue requirement and rates for both generation and distribution services.

ERRA Reasonableness Review for the Period September 1, 2001 through June 30, 2003

On October 3, 2003, SCE submitted its first ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. The CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA recommended disallowances that totaled approximately $14 million of costs recovered through the PROACT mechanism during the period from September 1, 2001 through June 30, 2003. In April 2004, SCE reached an agreement with the ORA (subject to CPUC approval) to reduce the PROACT disallowances to approximately $4 million. On January 27, 2005, the CPUC issued a decision approving the agreement. The $4 million, which is mainly comprised of ISO grid management charges and employee-related retraining costs, will be refunded to ratepayers through a credit to the ERRA.

The January 27, 2005 CPUC decision also provides that SCE's administration of its procurement contracts will be subject to reasonableness review under the "reasonable manager" standard. However, the CPUC decision provides that the review of SCE's daily dispatch of its generation resources will be subject to a compliance review, not a reasonableness review, and will only include a review of spot market transactions in the day-ahead, hour-ahead and real-time markets. The decision found that SCE's daily dispatch decisions during the record period complied with the CPUC's standard, and that its administration of its contracts was reasonable in all respects. It authorized recovery of amounts paid to Peabody Coal Company for costs associated with the Mohave mine closing as well as transmission costs related to serving municipal utilities, and also resolved outstanding issues from 2000 and 2001 related to CDWR costs. As a result of this decision, SCE recorded a pre-tax net regulatory gain of $118 million in 2004.

ERRA Reasonableness Review for the Period July 1, 2003 through December 31, 2003

On April 1, 2004, SCE submitted its second ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from July 1, 2003 through December 31, 2003, to be reasonable. In addition, SCE requested recovery of a $10 million reward for Palo Verde Nuclear Generating Station (Palo Verde) Unit 3 efficient operation and $5 million in electric energy transaction administration costs.

On January 17, 2005, the CPUC issued a decision finding that SCE's administration of its power purchase agreements and its daily decisions dispatching its procurement resources were reasonable and prudent. The decision also found that the revenue and expenses recorded in SCE's ERRA account during the record period were reasonable and prudent, and approved SCE's requested recovery of the items discussed above.

2005 ERRA Forecast

SCE submitted an ERRA forecast application on August 2, 2004, in which it forecasted a procurement-related revenue requirement for the 2005 calendar year of $3.0 billion, an increase of $733 million over 2004. The forecast increase is primarily due to a reduction in expected power purchases by the CDWR. On February 2, 2005, the CPUC issued a proposed decision adopting SCE's requested revenue requirement for the 2005 calendar year. A final decision is expected in March 2005.

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. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) (collectively, the investor-owned utilities). Amounts billed to SCE's customers for electric power purchased and sold by the CDWR (approximately $2.5 billion in 2004) are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings.

In December 2004, the CPUC issued its decision on how the CDWR's power charge revenue requirement for 2004 through 2013, when the last CDWR contract expires, will be allocated among the investor-owned utilities. The CPUC rejected a settlement agreement among PG&E, the Utility Reform Network (TURN), and SCE and which the ORA supported. However, the CPUC's final decision adopts key attributes of that settlement agreement. It adopts a cost-follows-contract allocation to each of the investor-owned utilities of the unavoidable portion of costs incurred under CDWR contracts. A previous CPUC decision allocated the avoidable portion of the costs on a cost-follows-contract basis. Allocating the avoidable and unavoidable portions on a cost-follows-contract basis provides the investor-owned utilities the appropriate incentives to operate and administer the contracts that have been allocated to them. In addition, in order to fairly allocate the total burden of the CDWR contracts among the investor-owned utilities, the decision adjusts the cost-follows-contract allocation of the total costs (avoidable and unavoidable) such that the above-market cost burden associated with the contracts is allocated as follows: 44.8% to PG&E's customers, 45.3% to SCE's customers, and 9.9% to SDG&E's customers. The CPUC's December 2004 decision is based on the above market cost analysis that SCE presented in its initial testimony in December 2003.

In response to an application filed by SDG&E, the CPUC issued an order granting limited rehearing of the December 2004 decision. The rehearing permits parties to present alternative methodologies and updated data for the calculation of above market costs associated with the CDWR contracts. A schedule has not been adopted for the rehearing, but it is expected to take place in the second quarter of 2005. SDG&E has also filed a petition for modification of the decision urging the CPUC to replace the adopted methodology with a methodology that would retain the cost-follows-contract allocation of the avoidable costs, but would allocate the unavoidable costs associated with the contracts: 42.2% to PG&E's customers, 47.5% to SCE's customers, and 10.3% to SDG&E's customers. Such an allocation would decrease the total costs allocated to SDG&E's customers and increase the total costs allocated to SCE's customers. The CPUC is expected to act on the petition in March 2005.

Direct Access and Community Choice Aggregation

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. In September 2001, the CPUC suspended the right of retail end-use customers to acquire direct access service until the CDWR no longer procures power for retail end-user customers. In addition, a 2002 California law authorized community choice aggregation which is a form of direct access that 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.

As a result of these customer options, the CPUC issued decisions or 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. Separately, the CPUC opened a proceeding to identify issues relating to the implementation of community choice aggregation and adopted a similar exit fee approach for customers who switch to community choice aggregation service. The charges recovered from these customers are used to reduce SCE's rates to bundled service customers and have no impact on earnings. These decisions and proceedings affect 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.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its net-short position (expected load requirements exceed generation supply) 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. Currently, the CPUC and the California Energy Commission are working together to set rules for various aspects of generation procurement which are described below.

Procurement Plan

Resource Planning Component of the Procurement Plan

On April 1, 2004, the CPUC instituted a resource planning proceeding that, among other things, will coordinate consideration of long-term resource plans. On July 9, 2004, SCE filed testimony on its long-term procurement plan, which includes a substantial commitment to cost-effective energy efficiency and an advanced load-control program. A CPUC decision approving SCE's long-term procurement plan was issued in December 2004. The decision required all long-term procurement to be conducted through all-source solicitations; allowed the consideration of debt equivalence in the bid evaluation process; and required the use of a greenhouse gas adder as a bid evaluation component. The decision also extended the utilities' authority to procure longer-term products and lifted the affiliate ban on long-term power products. SCE's next long-term procurement plan will be filed in 2006.

Assembly Bill 57 Component of the Procurement Plan

In December 2003, the CPUC adopted a 2004 short-term 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. Currently, SCE is operating under this approved short-term procurement plan. To the extent SCE procures power in accordance with the plan, SCE receives full-cost recovery of its procurement transactions pursuant to Assembly Bill 57. Accordingly, the plan is referred to as the Assembly Bill 57 component of the procurement plan.

Each quarter, SCE is required to file a report with the CPUC demonstrating that SCE's procurement-related transactions associated with serving the demands of its bundled electricity customers were in conformance with SCE's adopted short-term procurement plan. SCE has submitted seven quarterly compliance filings covering the period from January 1, 2003 through September 30, 2004, including its third quarter 2004 compliance filing on November 1, 2004. To date, however, the CPUC has only issued one resolution approving SCE's first compliance report for the period January 1, 2003 to March 31, 2003. While SCE believes that all of its procurement transactions were in compliance with its adopted short-term procurement plan, SCE cannot predict with certainty whether or not the CPUC will agree with SCE's interpretation regarding some elements.

Resource Adequacy Requirements

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. On October 28, 2004, the CPUC issued a decision clarifying the January 2004 decision. The October 2004 decision requires load-serving entities to ensure that adequate resources have been contracted to meet that entity's peak forecasted energy resource demand and an additional planning reserve margin of 15-17% of that peak load by June 1, 2006. Currently, the decision requires SCE to demonstrate that it has contracted 90% of its May–September 2006 resource adequacy requirement by September 30, 2005. As the May–September period approaches, SCE will be required to fill out the remaining 10% of its resource adequacy requirement one month in advance of expected need. The October 28, 2004 decision also clarified that although the first compliance filing will only cover May–September 2006, the 15-17% planning reserve margin is a year-round requirement. In its October 2004 decision, the CPUC also decided that long-term CDWR contracts allocated to the investor-owned utilities during the 2001 energy crisis are to be fully counted for resource adequacy purposes, and that deliverability standards developed during subsequent phases will be applied to such contracts. These deliverability standards, as well as a wide range of other issues, including scheduling and load forecasting, will be addressed in a separate phase of the proceeding which is expected to be completed by mid-2005. SCE expects to meet its resource adequacy requirements by the deadlines set forth in the decision.

Avoided Cost Proceeding

SCE purchases electric energy and capacity from various QFs pursuant to contracts that provide for payment at avoided cost, as determined by the CPUC. On April 22, 2004, the CPUC opened a rulemaking to develop, review and update methodologies for determining avoided costs, including the methodologies SCE uses to pay its QFs. Among other things, the rulemaking is to consider modifications to the current methodology for short-run avoided cost energy pricing and the current as-available capacity pricing. The rulemaking also proposes to develop a long-run avoided cost pricing methodology for QFs. Hearings are scheduled for May 2005. Although the rulemaking may affect the amounts paid to QFs and customer rates, changes to pricing methodology should not affect SCE's earnings as such costs are recovered from ratepayers, subject to reasonableness review.

Extension of QF Contracts and New QF Contracts

SCE has 270 power-purchase contracts with QFs, a number of which will expire in the next five years. On September 30, 2004, the CPUC issued a ruling requesting proposals and comments on the development of a long-term policy for expiring QF contracts and new QFs. SCE filed its response to the ruling on November 10, 2004, in which it proposed to purchase electricity from QFs by (1) allowing QFs to compete in SCE's competitive solicitations; (2) conducting bilateral negotiations for new contracts or contract extensions with QFs; or (3) offering an energy-only contract at market-based avoided cost prices. Hearings are scheduled for May 2005.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, and 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. At year-end 2004, SCE obtained approximately 18% of its power supplies from renewable resources. 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. In June 2004, the CPUC issued two decisions adopting additional rules on renewable procurement: a decision adopting standard contract terms and conditions and a decision adopting a market-price methodology. In July 2004, the CPUC issued a decision adopting criteria for the selection of least-cost and best-fit renewable resources. In December 2004, an assigned commissioner's ruling and scoping memo was issued establishing a schedule for addressing various renewable procurement-related issues that were not resolved by prior rulings and decision and directing the utilities to file renewable procurement plans addressing their 2005 renewable procurement goals and a plan for renewable procurement over the period 2005-2014. SCE's 2005 renewable procurement plan was filed on March 7, 2005.

SCE received bids for renewable resource contracts in response to a solicitation it made in August 2003 and conducted negotiations with bidders regarding potential procurement contracts. On March 8, 2005, SCE filed an advice letter with the CPUC requesting approval of 6 renewable contracts. SCE expects a CPUC decision on its advice letter by the second quarter of 2005. The procedures for measuring renewable procurement are still being developed by the CPUC. Based upon the current regulatory framework, SCE anticipates that it will comply, even without new renewable procurement contracts, with renewable procurement mandates through at least 2005. Beyond 2005, SCE will either need to sign new contracts and/or extend existing renewable QF contracts.

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.

On January 28, 2005, the CPUC opened a new phase of its procurement proceeding to consider the reallocation of certain CDWR contracts. Evidentiary hearings may be held later this year.

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 any 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 enhanced pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

On December 2, 2004 the CPUC issued a final decision on the application. Principally, the decision: (1) directs SCE to continue the ongoing negotiations and other efforts toward resolving the post-2005 coal and water supply issues; (2) directs SCE to conduct a study of potential generation resources that might serve as alternatives or complements to Mohave including solar generation and coal gasification; (3) provides an opportunity for SCE to recover in future rates certain Mohave-related costs that SCE has already incurred or is expected to incur by 2006, including certain preliminary engineering costs, water study costs and the costs of the study of potential Mohave alternatives; and (4) authorizes SCE to establish a rate-making account to track certain worker protection-related costs that might be incurred in 2005 in preparation for a temporary or permanent Mohave shutdown after 2005.

In parallel with the CPUC proceeding, negotiations have continued among the relevant parties in an effort to resolve the coal and water supply issues. Since November 2004, the parties have engaged in negotiations facilitated by a professional mediator, but no final resolution has been reached. In addition, agencies of the federal government are now conducting both a hydro-geological study and an environmental review regarding a possible alternative groundwater source for the slurry water; these studies, projected to cost approximately $6 million, are being funded by SCE and the other Mohave co-owners subject to the terms and conditions of a 2004 memorandum of understanding among the Mohave co-owners, the Tribes and the federal government.

The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but the presence or absence of Mohave as an available resource beyond 2005 will impact SCE's long-term resource plan. The outcome of this matter is not expected to have a material impact on earnings.

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

In light of the issues discussed above, in 2002 SCE concluded that it was probable Mohave would be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million in 2002. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded in regulatory assets as a long-term receivable to be collected from customer revenue. This treatment was based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates (together with a reasonable return) through a balancing account mechanism, as presented in its May 17, 2002 application and discussed in its supplemental testimony filed in January 2003.

San Onofre Nuclear Generating Station

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

Units 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 filed an application with the CPUC seeking a decision that it is reasonable for SCE to replace the San Onofre Units 2 and 3 steam generators and establishing appropriate ratemaking for recovery in rates of the reasonable cost of the replacement project. In June 2004, the CPUC established a schedule providing for a final CPUC decision in September 2005. Evidentiary hearings were held between January 31, 2005, and February 11, 2005.

The ORA has proposed that the CPUC disallow recovery of between 28.75% and 32.5% of the costs of steam generator replacement project costs or, in the alternative, require SCE to bear an equivalent percentage of the assumed replacement power costs if the steam generator replacement does not go forward and, as a result, San Onofre Units 2 and 3 experience reduced or suspended periods of operation in the future. ORA contends that SCE should incur one of these alternative consequences due to its alleged imprudence in failing to pursue claims against the manufacturer of the steam generators or its successors and/or in providing a broader release to the manufacturer than was allegedly appropriate. Assuming currently estimated project costs, including construction financing costs, a 32.5% proposed disallowance could be about $260 million. SCE is vigorously opposing ORA's proposed disallowance as unwarranted and confiscatory. TURN has also recommended that the CPUC find SCE's failure to pursue claims against the steam generator manufacturer and providing a broader release to the manufacturer than was allegedly appropriate to be unreasonable. However, TURN has not recommended that the CPUC adopt a specific disallowance amount. A CPUC decision on the proposed disallowance is expected at the same time as the CPUC's decision on SCE's application for steam generator replacement.

On September 30, 2004, SCE entered into a contract for steam generator fabrication. By the time of the CPUC's scheduled decision in September 2005, SCE anticipates that it will have incurred approximately $50 million in steam generator fabrication and associated project costs. SCE will seek recovery of these costs in the event that the CPUC does not authorize SCE to go forward with steam generator replacement. If the CPUC authorizes SCE to go forward with steam generator replacement, SCE will recover all of these costs that are reasonably incurred as part of the steam generator replacement capital costs.

Under the San Onofre operating agreement among the co-owners, a co-owner may elect to reduce its ownership share in lieu of paying its share of the cost of repairing an "operating impairment," as such term is defined in the San Onofre operating agreement. SCE has declared an "operating impairment" in connection with the need for steam generator replacement. SDG&E and the City of Anaheim have elected to reduce their respective 20% and 3.16% ownership shares rather than participate in the steam generator replacement project. The other co-owner, the City of Riverside (which owns 1.79% of the units), has elected to participate in the project. If steam generator replacement proceeds, SDG&E's and the City of Anaheim's ownership shares of San Onofre Units 2 and 3 will, upon completion of the project, be reduced in accordance with the formula set forth in the operating agreement. Under the formula, the City of Anaheim's share of San Onofre Units 2 and 3 will be reduced to zero percent. SDG&E disputed the proper application of the formula. As a result, the matter was subject to arbitration. The arbitrator's decision was issued on February 18, 2005. Assuming the cost of steam generator replacement is not significantly lower than currently estimated, under the arbitrator's decision, SDG&E's ownership share would also be reduced to zero percent under the arbitrator's decision. Under the terms of the operating agreement, the decision of the arbitrator is subject to approval by the CPUC. The transfer of all or any portion of SDG&E's and the City of Anaheim's respective ownership share as a result of their election not to participate in steam generator replacement will require Nuclear Regulatory Commission approval. The transfer of all or any portion of SDG&E's ownership share to SCE will also require CPUC approval.

San Onofre Reactor Vessel Heads

During the ongoing San Onofre Unit 3 refueling outage in the fourth quarter of 2004, SCE conducted a planned inspection of the Unit 3 reactor vessel head and found indications of degradation. Although the indications were far below the level at which leakage would occur, SCE repaired these indications using readily available tooling and a Nuclear Regulatory Commission-approved repair technique. While this was San Onofre's first experience of this kind of degradation to the reactor vessel head, the detection and repair of similar degradation is now common in the industry. SCE plans to replace the Unit 2 and 3 reactor vessel heads during the planned refueling outages in 2009–2010.

San Onofre Pressurizer Heater Sleeve Replacement

San Onofre Units 2 and 3 each include a pressurizer tank that contains 30 heater penetrations fabricated from the same material used in the steam generator tubes. These penetrations, also known as sleeves, are 13-inch long sections of pipe welded into the bottom of the pressurizer. During the recent Unit 3 outage, SCE performed inspections of two sleeves and found evidence of degradation. Degradation of the pressurizer sleeves has been a concern in the nuclear industry for some time, and SCE had been planning to replace all of the sleeves in both units during their next scheduled refueling outages in 2005 and 2006, respectively. With the discovery of sleeve degradation, SCE decided to move the planned replacement of 29 of the 30 Unit 3's sleeves forward from 2006 into the 2004 outage. This extra work extended the outage from 55 days to 92 days. This outage reduced the 2004 capacity factor of Unit 3 to 74%. The CPUC will review the reasonableness of outage-related capital costs and replacement power costs in future rate-making proceedings. SCE believes the costs are reasonable, recovery of the costs should be authorized, and the acceleration of the needed repairs should not impact earnings.

Palo Verde Steam Generators

The steam generators at Palo Verde, in which SCE owns a 15.8% interest, have material properties that are similar to 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 Unit 1 in 2005 and in Unit 3 in the 2007 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 $115 million; SCE expects to recover these costs through the rate-making process.

Inspections of Palo Verde Units 1, 2 and 3 reactor vessel heads were performed during scheduled refueling and maintenance outages in 2003 and 2004 and no indications of leakage or degradation were found.

Transmission and Distribution

2003 General Rate Case Proceeding

On May 3, 2002, SCE filed its application for a 2003 GRC, requesting an increase of $286 million in SCE's base rate revenue requirement, which was subsequently revised to an increase of $251 million. 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 incremental cost incentive pricing (ICIP) rate-making mechanism at year-end 2003 and a forecast of increased sales.

The CPUC issued a final decision on SCE's 2003 GRC application on July 8, 2004, authorizing an annual increase of approximately $73 million in base rates, retroactive to May 22, 2003 (the date a final CPUC decision was originally scheduled to be issued). The decision also authorized a base rate revenue decrease of $49 million in 2004, and a subsequent increase of $84 million in 2005. During the second quarter of 2004, SCE recorded a pre-tax net regulatory gain of $180 million as a result of the implementation of the 2003 GRC decision, primarily relating to the recognition of revenue from the rate recovery of pension contributions during the time period that the pension plan was fully funded, the resolution of the allocation of costs between transmission and distribution for 1998 through 2000, partially offset by the deferral of revenue previously collected during the ICIP mechanism for dry cask storage. The gain was included in the caption "provisions for regulatory adjustment clauses—net" on the income statement.

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 and the date a final decision was adopted. In July 2004, SCE submitted an advice filing to record the amount in this memorandum account and recorded an approximate $55 million pre-tax gain in the third quarter of 2004 included in the caption "operating revenue" on the income statement. In addition, during the third quarter of 2004 SCE recorded approximately $48 million in pre-tax gains related to the 1997–1998 generation-related capital additions ($31 million, which is included in the caption "provisions for regulatory adjustment clauses—net" on the income statement) and the related rate recovery ($17 million, which is included in the caption "operating revenue" on the income statement).

The amount recorded in the GRC memorandum account is being recovered in rates together with the 2004 revenue requirement authorized by the CPUC in the GRC decision. The GRC rate increase was combined with other rate changes from pending rate proceedings and became effective August 5, 2004.

2006 General Rate Case Proceeding

On December 21, 2004, SCE filed its application for a 2006 GRC, requesting an increase of $370 million in SCE's 2006 base rate revenue requirement, primarily for capital-related expenditures to accommodate customer and load growth and substantially higher operation and maintenance expenditures particularly in SCE's transmission and distribution business unit. SCE also requested that the CPUC authorize continuation of SCE's existing post-test year rate-making mechanism, which would result in base rate revenue increases of $159 million and $122 million in 2007 and 2008, respectively. If the CPUC approves these requested increases and allocates them to ratepayer groups on a system average percentage change basis, the total increase over current base rates is estimated to be 10%. A decision on SCE's 2006 GRC is expected in December 2005.

2005 Cost of Capital

SCE's annual cost of capital applications with the CPUC are required to be filed in May of each year, with decisions rendered in such proceedings becoming effective January 1 of the following year. On May 10, 2004, SCE filed an application requesting the CPUC to maintain for 2005 the currently authorized 11.60% return on common equity for SCE's CPUC-jurisdictional assets. SCE also requested a change in its authorized capital structure to offset the effects of debt equivalence of power-purchase agreements and revised SCE's projected costs of long-term debt and preferred stock. SCE's overall request projected a decrease in revenue requirements of approximately $28 million.

On December 16, 2004, the CPUC issued a final decision granting an 11.4% return on common equity and debt equivalent recognition through a higher preferred equity capitalization ratio. The decision resulted in a $47 million decrease in revenue requirements due to lower interest costs and the reduced return on equity and an overall rate of return of 9.07% on CPUC-jurisdictional assets.

Transmission Proceeding

In August and November 2002, the FERC issued opinions affirming a September 1999 administrative law judge decision to disallow, among other things, recovery by SCE and the other California public utilities of costs reflected in network transmission rates associated with ancillary services and losses incurred by the utilities in administering existing wholesale transmission contracts after implementation of the restructured California electric industry. SCE has incurred approximately $80 million of these unrecovered costs since 1998. After the three California utilities appealed the decisions to the United States Court of Appeals for the D.C. Circuit, the FERC filed a motion with the D.C. Circuit Court seeking voluntary remand to permit issuance of a further order. On February 12, 2004, the D.C. Circuit Court granted the FERC's motion and remanded the record back to the FERC for further consideration. On May 6, 2004, the FERC issued its order reaffirming its earlier decisions. SCE and the other two California utilities are pursuing the appeal before the D.C. Circuit Court, and filed their opening briefs with the D.C. Circuit Court on October 12, 2004. Oral argument is set for May 9, 2005.

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 and ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets. Under the 2001 CPUC settlement agreement, mentioned in "—Generation and Power Procurement—CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE net of costs will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company (El Paso) entered into a settlement agreement with a number of parties (including SCE, PG&E, the State of California and various consumer class action representatives) settling various claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso 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 United States District Court has issued an order approving the stipulated judgment and the settlement agreement has become effective. Pursuant to a CPUC decision, SCE will refund to customers amounts received under the terms of the El Paso settlement (net of legal and consulting costs) through its ERRA mechanism. In June 2004, SCE received its first settlement payment of $76 million. Approximately $66 million of this amount was credited to purchased-power expense, and will be refunded to SCE's ratepayers through the ERRA over the next 12 months, and the remaining $10 million was used to offset SCE's incurred legal costs. Additional settlement payments totaling approximately $127 million are due from El Paso over a 20-year period. As a result, SCE recorded a receivable and corresponding regulatory liability of $65 million in 2004 for the discounted present value of the future payments (discounted at an annual rate of 7.86%). Amounts El Paso refunds to the CDWR will result in reductions in the CDWR's revenue requirement allocated to SCE in proportion to SCE's share of the CDWR's power charge revenue requirement.

On July 2, 2004, the FERC approved a settlement agreement between SCE, SDG&E and PG&E and The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds and other payments to the settling purchasers and others against some of Williams' power charges in 2000–2001. In August 2004, SCE received its $37 million share of the refunds and other payments under the Williams settlement.

On April 26, 2004, SCE, PG&E, SDG&E and several California state governmental entities agreed to settlement terms with West Coast Power, LLC and its owners, Dynegy Inc. and NRG Energy, Inc. (collectively, Dynegy). The settlement terms provide for refunds and other payments totaling $285 million, with a proposed allocation to SCE of approximately $42 million. The Dynegy settlement terms were approved by the FERC on October 25, 2004 and SCE received its $42 million share of the settlement proceeds in November 2004.

On July 12, 2004, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Duke Energy Corporation and a number of its affiliates (collectively Duke). The settlement terms agreed to with the Duke parties provide for refunds and other payments totaling in excess of $200 million, with a proposed allocation to SCE of approximately $45 million. The Duke settlement was approved by the FERC on December 7, 2004 and SCE received its $45 million share of the settlement proceeds in January 2005.

On January 14, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in a Chapter 11 bankruptcy proceeding pending in Texas. Among other things, the settlement terms provide for expected cash and equivalent refunds totaling $320 million, of which SCE's allocated share is approximately $68 million. The settlement also provides for an allowed, unsecured claim totaling $175 million in the bankruptcy of one of the Mirant parties, with SCE being allocated approximately $33 million of the unsecured claim. The actual value of the unsecured claim will be determined as part of the resolution of the Mirant parties' bankruptcies. The Mirant settlement was submitted to the FERC for its approval on January 31, 2005 and was submitted to the Mirant bankruptcy court for its approval on February 23, 2005.

On November 19, 2004, the CPUC issued a resolution authorizing SCE to establish an Energy Settlement Memorandum Account (ESMA) for the purpose of recording the foregoing settlement proceeds from energy providers and allocating them in accordance with the terms of the CPUC litigation settlement agreement. The resolution accordingly provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA will be allocated to recovery of SCE's litigation costs and expenses in the FERC refund proceedings described above and as a shareholder incentive pursuant to the CPUC litigation settlement agreement. Remaining amounts for each settlement are to be refunded to ratepayers through the ERRA mechanism. In 2004, SCE recorded in the caption "Other nonoperating income" on the income statement a total of $12 million as shareholder incentives related to refunds received in 2004.

Other Regulatory Matters

Catastrophic Event Memorandum Account

The catastrophic event memorandum account (CEMA) is a CPUC-authorized mechanism established in 1991 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 a CEMA associated with the fires that occurred in SCE territory in October 2003. Costs tracked through the CEMA mechanism may be recovered in future rates after SCE's filing of a request with the CPUC, a showing of their reasonableness and approval by the CPUC 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 assist local jurisdictions in responding to this emergency by ensuring that all dead, dying and diseased trees and vegetation are completely cleared from their utility rights-of-way to mitigate the risk of fire. SCE's role in this effort is to support the State of California, federal and local agencies by hiring contractors who are capable of removing these trees and vegetation in a vast area for the purpose of protecting against potential damage that may occur from fires and the collapse or falling of these tress into SCE's electrical lines and facilities. SCE estimates that it may incur over $100 million 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. As of December 31, 2004, the bark beetle CEMA had a balance of $131 million. On September 23, 2004, the CPUC issued a resolution on SCE's advice filing granting recovery of the majority of the $18 million bark beetle related costs recorded in 2003. The CPUC disallowed approximately $500,000 in recorded costs based on the assertion that such costs were already recovered in rates under SCE's routine line-clearing program. The CPUC also modified its original authorization and now requires future bark beetle CEMA filings to be applications instead of advice letters. SCE estimates that it will spend approximately $40 million on this project in 2005 and approximately $45 million in both 2006 and 2007. SCE will submit an application to recover the 2004 costs in 2005.

Fire-Related CEMA

In October and November of 2003, wildfires damaged SCE's electrical infrastructure, primarily in the San Bernardino Mountains of southern California where an estimated 2,085 power poles, 2,059 services, 371 transformers, 557,033 of overhead conductors and 25,822 feet of underground cable were replaced or repaired. SCE notified the CPUC that it initiated a CEMA on October 21, 2003 to track the incremental costs to repair and restore its infrastructure. As of December 31, 2004, the fire-related CEMA had a balance of $12 million. The total costs associated with the fire-related CEMA, as of December 31, 2005, are expected to be $16 million. SCE filed an application with the CPUC on December 2, 2004 to seek recovery of its fire-related costs over a one-year period commencing January 1, 2006. In addition, SCE is requesting that the CPUC find reasonable $28 million of incremental capital expenditures, which would be recovered in rates over the useful life of the particular asset.

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 May 21, 2004, the Court of Appeal issued its decision in the two consolidated cases, and denied the utilities' and their holding companies' challenges to both CPUC decisions. The Court of Appeal held that the CPUC has limited jurisdiction to enforce in a CPUC proceeding the conditions agreed to by holding companies incident to their being granted authority to assume ownership of a CPUC-regulated utility. The Court of Appeal held that the CPUC's decision interpreting the first priority requirement was not reviewable because the CPUC had not made any ruling that any holding company had violated the first priority requirement. However, the Court of Appeal suggested that if the CPUC or any other authority were to rule that a utility or holding company violated the first priority requirement, the utility or holding company would be permitted to challenge both the finding of violation and the underlying interpretation of the first priority requirement itself. On June 30, 2004, Edison International and the other utility holding companies filed with the California Supreme Court a petition for review of the Court of Appeal decision as to jurisdiction over holding companies, but they and the utilities did not file a challenge to the decision as to the first priority issue. On September 1, 2004, the California Supreme Court denied the petition for review. The Court of Appeal's decision, as to jurisdiction, is now final.

The original order instituting the investigation into whether the utilities and their holding companies have complied with CPUC decisions and applicable statutes remains in effect. However, on February 11, 2005, an administrative law judge ruling was issued which provides that any party to the proceedings that believes the proceedings should remain open has 30 days to file comments listing matters that remain to be decided and explaining why they must be resolved at the CPUC rather than in another forum. The CPUC indicated that if comments are not received in the 30 day time period, a decision closing the proceeding will be prepared for CPUC consideration and no further comment will be allowed. At this time, SCE is not aware whether or not comments have been received or whether the CPUC has taken further action.

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 customer satisfaction, employee injury and illness reporting, and system reliability.

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

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties to SCE under the PBR provisions for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003.

SCE has been conducting an internal investigation and keeping the CPUC informed of its progress. On June 25, 2004, SCE submitted to the CPUC a PBR customer satisfaction investigation report, which concluded that employees in the design organization of the transmission and distribution business unit deliberately altered customer contact information in order to affect the results of customer satisfaction surveys. At least 36 design organization personnel engaged in deliberate misconduct including alteration of customer information before the data were transmitted to the independent survey company. Because of the apparent scope of the misconduct, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forego an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997–2003). In addition, during its investigation, SCE determined that it could not confirm the integrity of the method used for obtaining customer satisfaction survey data for meter reading. Thus, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading. As a result of these findings, SCE accrued a $9 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refunds of rewards that have been received.

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

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

Employee Injury and Illness Reporting

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

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. Under the PBR mechanism, rewards and/or penalties for the years 1997 through 2003 were based upon a total incident rate, which included two equally weighted measures: Occupational Safety and Health Administration (OSHA) recordable incidents and first aid incidents. The major issue disclosed in the investigative findings to the CPUC was that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents. SCE's investigation also found reporting inaccuracies for OSHA recordable incidents, but the impact of these inaccuracies did not have a material effect on the PBR mechanism.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism for any year before 2005, and it return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001–2003 time frames.

SCE is taking other remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance. Additional actions, including disciplinary action against specific employees identified as having committed wrongdoing, may result once the investigation is completed. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004. As with the customer satisfaction matter, the CPUC has not yet opened a formal investigation into this matter. However, SCE anticipates that the CPUC will be submitting data requests and seeking additional information in the near future.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE is conducting an investigation into the third PBR metric, system reliability. Since the inception of PBR payments in 1997, SCE has received $8 million in rewards and has applied for an additional $5 million reward based on frequency of outage data for 2001. For 2002, SCE's data indicates that it earned no reward and incurred no penalty. Based on the application of the PBR mechanism, as adopted, SCE's data would result in penalties of $5 million and $1 million, for 2003 and 2004, respectively. These penalties have not yet been assessed. As a result of SCE's data and calculations, SCE has accrued a $6 million charge in the caption "Other nonoperating deductions" on the income statement in 2004.

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

OTHER DEVELOPMENTS

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.

On August 19, 2004, the CPUC issued an order instituting a rulemaking to update the CPUC's policies and procedures related to electromagnetic fields emanating from regulated utility facilities. SCE and other interested parties submitted comments to clarify the issues to be addressed in the proceeding in December 2004 and January 2005. It is anticipated that the CPUC will schedule a prehearing conference in the near future. SCE cannot predict with certainty the outcome of this proceeding.

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 24 identified sites is $82 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 $123 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also had 30 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $27 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 $55 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 2004 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 has had and expects to continue to have excess allowances under Phase II of the Clean Air Act.

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. 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 $8 million as of December 31, 2004) and the related regulatory asset (approximately $78 million as of December 31, 2004), 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 in the United States 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 (U.S. 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. The U.S. EPA has made information requests concerning SCE's Four Corners station. Other than these requests for information, no enforcement-related proceedings have been initiated against any SCE facilities by the U.S. EPA relating to NSR compliance.

Over this same period, the U.S. 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, the U.S. 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 over the next three years are: 2005 – $407 million; 2006 – $444 million; and 2007 – $530 million. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines.

Federal Income Taxes

Edison International has reached a tentative settlement with the Internal Revenue Service (IRS) on tax issues and pending affirmative claims relating to its 1991 to 1993 tax years currently under appeal. This settlement, which should be finalized in 2005, is expected to result in a net earnings benefit for SCE of approximately $70 million.

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

The IRS Revenue Agent Report for the 1997 to 1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

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

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss. The D.C. District Court denied these motions for dismissal, except for Salt River Project Agricultural Improvement and Power District's motion for its separate dismissal from the lawsuit.

Certain issues related to this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the United States Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE and Peabody filed motions to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. On April 13, 2004, the D.C. District Court denied SCE's and Peabody's April 2003 motions to dismiss or, in the alternative, for summary judgment. The D.C. District Court subsequently issued a scheduling order that imposed a December 31, 2004 discovery cut-off. Pursuant to a joint request of the parties, the D.C. District Court granted a 120-day stay of the action to allow the parties to attempt to resolve, through facilitated negotiations, all issues associated with Mohave. Negotiations are ongoing and the stay has been continued until further order of the court.

The United States Court of Appeals for the D.C. Circuit, acting on a suggestion on remand filed by the Navajo Nation, held in an October 24, 2003 decision that the Supreme Court's March 4, 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 D.C. Circuit Court decision. Both petitions were denied on March 9, 2004. On March 16, 2004, the D.C. Circuit Court issued an order remanding the case against the Government to the Court of Federal Claims, which conducted a status conference on May 18, 2004. As a result of the status conference discussion, the Navajo Nation and the Government are in the process of briefing the remaining issues following remand. Peabody's motion to intervene as a party in the remanded Court of Federal Claims case was denied.

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.

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

Income from Continuing Operations

SCE income from continuing operations in 2004 were $921 million, compared to income of $882 million in 2003 and income of $1.2 billion in 2002. SCE's 2002 income included a $480 million benefit related to the implementation of the CPUC utility-related generation (URG) decision. Excluding a $480 million benefit in 2002 related to a regulatory decision on SCE's utility-retained generation, SCE's income from continuing operations was $767 million in 2002. The $39 million increase between 2004 and 2003 was mainly due to the resolution of regulatory proceedings and prior years' tax issues which increased income by $86 million over 2003. The 2004 proceedings included the 2003 GRC that was resolved in July 2004 and the 2003 ERRA proceeding addressing power procurement reasonableness that was resolved in the fourth quarter of 2004. Also, in the fourth quarter of 2004, SCE favorably resolved prior years' tax issues. Excluding these items, income decreased $47 million, primarily from the expiration at year-end 2003 of the ICIP mechanism at San Onofre partially offset by the increase in revenue authorized by the 2003 GRC decision. Post-test-year revenue increases for 2004 and 2005, to compensate for customer growth and increased capital expenditures were authorized in the 2003 GRC decision. The $115 million increase between 2003 and 2002, excluding the $480 million benefit, 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 income 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.

Operating Revenue

SCE's retail sales represented over approximately 85% of operating revenue. Due to warmer weather during the summer months, operating revenue during the third quarter of each year is generally significantly higher than other quarters.

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

In millions Year ended December 31,	**2004 vs. 2003**	2003 vs. 2002
Operating revenue		
Rate changes (including surcharges)	**$ (707)**	$ (677)
Direct access credit	**—**	471
Sales volume changes	**(159)**	(60)
Sales for resale	**164**	394
SCE's variable interest entities	**285**	—
Other (including intercompany transactions)	**11**	20
Total	**$ (406)**	$ 148

Total operating revenue decreased by $406 million in 2004 (as shown in the table above). The reduction in operating revenue due to rate changes resulted from the implementation of a CPUC-approved customer rate reduction plan effective August 1, 2003 and the recognition of revenue in 2003 from a CPUC-authorized surcharge collected in 2002 used to recover costs incurred in 2003. There was no surcharge revenue recognized in 2004. The operating revenue reduction related to rate changes also reflects an increase in distribution rates and a further decrease in generation rates, effective in August 2004, resulting from the implementation of the 2003 GRC, and an allocation adjustment for the

CDWR energy purchases recorded in 2003. The decrease in electric revenue resulting from sales volume changes was mainly due to the CDWR providing a greater amount of energy to SCE's customers in 2004, as compared to 2003 (see discussion below), partially offset by an increase in kWh sold. Sales for resale increased due to a greater amount of excess energy in 2004, as compared to 2003. As a result of the CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times, which then is resold in the energy markets. SCE's variable interest entities revenue represents the recognition of revenue resulting from the consolidation of SCE's variable interest entities on March 31, 2004 (see "Critical Accounting Policies and Estimates" and "New Accounting Principles").

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 a CPUC-authorized temporary surcharge collected between June and December 2002, used to recover costs incurred in 2003. 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.

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 $2.5 billion, $1.7 billion, and $1.4 billion for the years ended December 31, 2004, 2003, and 2002, respectively.

Operating Expenses

Fuel Expense

Fuel expense increased $575 million in 2004 primarily due to the consolidation of SCE's variable interest entities resulting in the recognition of fuel expense of $578 million (see "New Accounting Principles").

Purchased-Power Expense

Purchased-power expense decreased $454 million in 2004 and increased $770 million in 2003. The 2004 decrease was mainly due to the consolidation of SCE's variable interest entities which resulted in a $669 million reduction in purchased-power expense (see "New Accounting Principles") and the receipt of approximately $190 million in settlement agreement payments between SCE and sellers of electricity and natural gas. See "Regulatory Matters—Transmission and Distribution—Wholesale Electricity and Natural Gas Markets" for a discussion of the settlements reached. The decrease was partially offset by higher expenses of approximately $150 million related to power purchased by SCE from QFs, as discussed below, higher expenses of approximately $100 million resulting from an increase in the number of gas bilateral contracts in 2004, as compared to 2003, and higher expenses of approximately $130 million related to ISO purchases. 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 by SCE from QFs, mainly due to higher spot natural gas prices in 2003 as compared to 2002.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. Energy payments to gas-fired QFs are generally tied to spot natural gas prices. Effective May 2002, energy payments for most renewable QFs were converted to a fixed price of 5.37¢-per-kWh. Average spot natural gas prices were higher during 2004 as compared to 2003, and were higher during 2003, as compared to 2002.

Provisions for Regulatory Adjustment Clauses – Net

Provisions for regulatory adjustment clauses – net decreased $1.3 billion in 2004 and $364 million in 2003. The 2004 decrease was mainly due to the collection of the PROACT balance in 2003 and the implementation of the CPUC-authorized rate-reduction plan in the summer of 2003, resulting in decreases of approximately $700 million. The decrease also reflects a net effect of approximately $335 million of regulatory adjustments, related to the implementation of SCE's 2003 GRC decision (see "Regulatory Matters—Transmission and Distribution—2003 General Rate Case Proceeding") and ERRA-related adjustments resulting from a CPUC decision received in January 2005 (see "Regulatory Matters—Generation and Power Procurement—Energy Resource Recovery Account Proceedings"), and the deferral of costs for future recovery in the amount of approximately $100 million associated with the bark beetle infestation (see "Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"). The decrease was partially offset by approximately $190 million in settlement agreement payments received and refunded to ratepayers and shareholder incentives (see "Regulatory Matters—Transmission and Distribution—Wholesale Electricity and Natural Gas Markets"), the favorable resolution of certain regulatory cases recorded in the third quarter of 2003 (as discussed below), and an allocation adjustment of approximately $110 million for CDWR energy purchases recorded in 2003. The 2003 decrease was mainly due to lower overcollections used to recover SCE's 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 2003 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.

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 Operation and Maintenance Expense

Other operating and maintenance expense increased $385 million in 2004 and $137 million in 2003. The 2004 increase was mainly due to approximately $130 million of costs incurred in 2004 related to the removal of trees and vegetation associated with the bark beetle infestation (see "Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"), higher operation and maintenance costs of approximately $60 million related to the San Onofre refueling outages in 2004, operating and maintenance expense of $66 million related to the consolidation of SCE's variable interest entities, higher operation and maintenance costs related to a scheduled major overhaul at SCE's Four Corners coal facility and additional costs for 2003 incentive compensation due to upward revisions in the computation in 2004.

These increases were partially offset by a decrease in postretirement benefits other than pensions, including the effects of adopting the Medicare Prescription Drug, Improvement and Modernization Act of 2003 in the third quarter of 2004 (see "New Accounting Principles" for further discussion) and lower worker's compensation claims in 2004. The 2003 increase 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.

Depreciation, Decommissioning and Amortization Expense

Depreciation, decommissioning and amortization expense decreased $22 million in 2004 and increased $102 million in 2003. The 2004 decrease was mainly due to a change in the Palo Verde and San Onofre rate-making mechanisms in 2003 and 2004, partially offset by an increase in SCE's depreciation associated with additions to transmission and distribution assets, the consolidation of SCE's variable interest entities, and an increase in nuclear decommissioning expense. The 2003 increase was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets, an increase in nuclear decommissioning expense, partially offset by a change in the amortization period for SCE's San Onofre recorded in the third quarter of 2002 based on the implementation of a CPUC decision.

Other Income and Deductions

Interest and Dividend Income

Interest and dividend income decreased $80 million in 2004 and $162 million in 2003, mainly due to the absence of interest income on the PROACT balance. At July 31, 2003, the PROACT balance was overcollected and was transferred to the ERRA on August 1, 2003. The 2003 decrease was also due to lower interest income from lower average cash balances, compared to the same period in 2002.

Interest Expense – Net of Amounts Capitalized

Interest expense – net of amounts capitalized decreased $48 million in 2004 and $127 million in 2003. The 2004 decrease was mainly due to lower interest expense on long-term debt resulting from the redemption of high interest rate debt by issuing new debt with lower interest rates. The 2003 decrease was due to higher interest expense in 2002 resulting from 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 SCE's long-term debt resulting from the early retirement of debt. In 2003 dividend payments on certain preferred securities were reclassified to interest expense. 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 and 2002 are not included in interest expense – net of amounts capitalized in the consolidated statements of income.

Other Nonoperating Deductions

Other nonoperating deductions increased $46 million in 2004 and $41 million 2003. The 2004 increase was mainly due to a $29 million pre-tax charge for the anticipated refund of the previously received performance incentive rewards as well as the accrual of $6 million in system reliability penalties (see "Regulatory Matters—Other Regulatory Matters—Investigation Regarding Performance Incentive Rewards"). The 2003 increase was due to the resolution of regulatory matters accrued for in 2002.

Minority Interest

Minority interest represents the effects of the adoption of a new accounting pronouncement in second quarter 2004 related to SCE's variable interest entities (see "Critical Accounting Policies and Estimates" and "New Accounting Principles").

Income Taxes

Income taxes increased $50 million in 2004 and decreased $254 million in 2003. The 2004 increase was primarily due to an increase in pre-tax income and the favorable resolution of a FERC rate case recorded by SCE in 2003. The increase was partially offset by adjustments made in 2004 to accrued tax liabilities to reflect the receipt of an IRS audit report and progress achieved in settlement negotiations for issues relating to prior year tax liabilities. The 2003 decrease was primarily due to reductions in pre-tax income, the favorable resolution of tax audit issues, and the favorable resolution of a FERC rate case, partially offset by the reestablishment of tax-related regulatory assets upon implementation of the URG decision recorded in 2002.

SCE's federal and state statutory tax rate was 40.37% for 2004 and 40.551% for the other years presented. The lower effective tax rate of 32.2% in 2004 was primarily due to adjustments to tax liabilities relating to prior years, property-related flow through items and other property-related adjustments. 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.

Income from Discontinued Operations

SCE's income 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 $2.3 billion in 2004, $2.6 billion in 2003 and $548 million in 2002. The 2004 decrease in cash provided by operating activities from continuing operations was mainly due to SCE's implementation of a CPUC-approved customer rate reduction plan effective August 1, 2003. The 2003 increase in cash provided by operating activities from continuing operations was mainly due to SCE's March 2002 repayment of past-due obligations. The change during both periods was also due to timing of cash receipts and disbursements related to working capital items.

Cash Flows from Financing Activities

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

SCE financing activities in 2004 include the issuance of $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034 and $150 million of floating rate bonds due in 2006 all issued during the first quarter of 2004. The proceeds from these issuances were used to call at par $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due

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

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

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.

Cash Flows from Investing Activities

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

Investing activities include capital expenditures of $1.7 billion, $1.2 million and $1.0 billion in 2004, 2003 and 2002, respectively, primarily for transmission and distribution assets, including approximately $70 million in 2004 for nuclear fuel acquisitions. In addition, investing activities in 2004 include $285 million of acquisition costs related to the Mountainview project.

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 $2.2 billion as of December 31, 2004, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. As of December 31, 2004, the decommissioning trust balance was $2.7 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.

DISPOSITIONS 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 2002 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.

ACQUISITION

On March 12, 2004, SCE acquired Mountainview Power Company LLC, which owns a power plant under construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project, which is expected to be completed in early 2006.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Asset Impairment

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

The assessment of impairment is a critical accounting estimate because significant management judgment is required to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors 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 standards for rate-regulated enterprises, this incurred cost was deferred and recorded in regulatory assets as a long-term receivable to be collected from customer revenue. This treatment was based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates (together with a reasonable return) through a balancing account mechanism. See "Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings," and "—Rate Regulated Enterprises."

Income Taxes

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

The accounting standard for income taxes requires the asset and liability approach for financial accounting and reporting for deferred income taxes. SCE uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each 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. SCE takes certain tax positions it believes are applied in accordance with tax laws. The application of these positions is subject to interpretation and audit by the IRS. As further described in "Other Developments—Federal Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain issues at SCE.

Management continually evaluates its income tax exposures and provides for allowances and/or reserves as 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 postretirement heath care plans. These critical assumptions are evaluated at least annually. Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

The discount rate enables SCE to state expected future cash flows at a present value on the measurement date. At the December 31, 2004 measurement date, SCE used a discount rate of 5.5% for pensions and 5.75% 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 7.5% for pensions and 7.1% for PBOP. A portion of PBOP trusts asset returns are subject to taxation, so the 7.1% figure above is determined on an after-tax basis. Actual time-weighted, annualized returns on the pension plan assets were 12.2%, 5.0% and 11.9% for the one-year, five-year and ten-year periods ended December 31, 2004, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 11.4%, 1.2% and 10.1% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

At December 31, 2004, SCE's pension plans had a $3.0 billion projected benefit obligation (PBO), a $2.6 billion accumulated benefit obligation (ABO) and $3.0 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $246 million, and a 1% increase would decrease the PBO by $266 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would increase pension expense by $28 million.

SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense 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, 2004, this cumulative difference amounted to a regulatory liability of $114 million, meaning that the rate-making method has resulted in recognizing $114 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 net income. The reduction to other comprehensive income would be restored through shareholders' equity in future periods to the extent the market value of trust assets exceeded the ABO. This assessment is performed annually.

At December 31, 2004, SCE's PBOP plans had a $2.1 billion PBO and $1.4 billion in plan assets. Total expense for these plans was $87 million for 2004. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2004 by $307 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, 2004 by $248 million and annual aggregate service and interest costs by $21 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. In May 2004, the Financial Accounting Standards Board (FASB) issued accounting guidance related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. SCE adopted this guidance effective July 1, 2004, which resulted in a decrease of $116 million to SCE's accumulated benefit obligation for postretirement benefits other than pensions. SCE's 2004 expense decreased approximately $8 million as a result of the subsidy. According to proposed federal regulations, SCE's retiree health care plans provide prescription drug benefits that are deemed to be actuarially equivalent to Medicare benefits. Accordingly, SCE recognized the subsidy in the measurement of its accumulated obligation and recorded an actuarial gain.

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, 2004, the Consolidated Balance Sheets included regulatory assets of $3.8 billion and regulatory liabilities of $3.8 billion. 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) restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision in the second quarter of 2002; and (2) 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 "Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings" section.

NEW ACCOUNTING PRINCIPLES

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. SCE currently uses the intrinsic value accounting method for stock-based compensation. SCE will adopt the new method effective July 1, 2005. The difference in expense, net of tax, between the two methods is $4 million. SCE is reviewing the new standard and has not yet selected a transition method for adoption of the new standard.

In December 2004, the FASB issued guidance (Staff Position 109-1) on accounting for a tax deduction resulting from the American Jobs Creation Act of 2004. The primary objective of this Position is to provide guidance on accounting for the provision within the American Jobs Creation Act of 2004 that provides a tax deduction on qualified production activities. Under this Position, recognition of the tax deduction on qualified production activities, which include the production of electricity, is reported in the year it is earned. This FASB Staff Position had no material impact on SCE's financial statements. SCE is evaluating the effect that the manufacturer's deduction will have in subsequent years.

In December 2003, the FASB issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of VIEs. The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, VIEs, where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE unless specific exceptions apply. This Interpretation was 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.

SCE has 270 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 under terms and pricing controlled by the CPUC. SCE conducted a review of its QF contracts and determined that SCE has variable interests in 12 contracts with gas-fired cogeneration plants that are potential VIEs and that contain variable pricing provisions based on the price of natural gas and for which SCE does not have sufficient information to determine if the projects qualify for a scope exception. SCE requested from the entities that hold these contracts the financial information necessary to determine whether SCE must consolidate these projects. All 12 entities declined to provide SCE with the necessary financial information. However, four of the 12 contracts are with entities 49%-50% owned by a related party, Edison Mission Energy (EME). EME is an indirect wholly owned subsidiary of SCE's parent company, Edison International. Although the four related-party entities have declined to provide their financial information to SCE, Edison International has access to such information and has provided combined financial statements to SCE. SCE has determined that it must consolidate the four power projects partially owned by EME based on a qualitative analysis of the facts and circumstances of the entities, including the related-party nature of the transaction. SCE will continue to attempt to obtain information for the other eight projects in order to determine whether they should be consolidated by SCE.

The remaining 258 contracts will not be consolidated by SCE under the new accounting standard, since SCE lacks a variable interest in these contracts or the contracts are with governmental agencies, which are generally excluded from the standard.

SCE analyzes its potential variable interests by calculating operating cash flows. A fixed-price contract to purchase electricity from a power plant does not transfer sufficient risk to SCE to be considered a variable interest. A contract with a non-natural-gas-fired plant that is based on the price of natural gas is also not a variable interest. SCE has other power contracts with non-QF generators. SCE has determined that these contracts are not significant variable interests.

COMMITMENTS AND INDEMNITIES

SCE's commitments for the years 2005 through 2009 and thereafter are estimated below:

In millions	2005	2006	2007	2008	2009	Thereafter
Long-term debt maturities and sinking fund requirements[1]	$ 503	$ 1,168	$ 1,580	$ 255	$ 418	$ 5,704
Fuel supply contract payments	173	58	65	59	36	454
Purchased-power capacity payments	898	725	648	421	394	3,059
Unconditional purchase obligations	5	5	5	5	6	43
Estimated noncancelable lease payments	48	45	9	8	5	9
Preferred stock redemption requirements	9	9	74	56	—	—
Employee benefit plans contributions[2]	109	126	127	—	—	—

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2004, assuming long-term debt is held to maturity, and related forecast interest payments over the applicable period of the debt.

(2) Amount includes estimated contributions to the pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2007 are not available.

Fuel Supply Contracts

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

Power Purchase Contracts

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

Unconditional Purchase Obligations

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the transmission line is operable.

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates. Additionally, in accordance with an accounting standard, certain power contracts in which SCE takes virtually all of the power from specific power plants are classified as operating leases.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. The generating station has not operated since early 2001, and SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and 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, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

PricewaterhouseCoopers LLP

Los Angeles, California
March 15, 2005

In millions Year ended December 31,	**2004**	2003	2002
Operating revenue	**$ 8,448**	$ 8,854	$ 8,706
Fuel	**810**	235	243
Purchased power	**2,332**	2,786	2,016
Provisions for regulatory adjustment clauses – net	**(201)**	1,138	1,502
Other operation and maintenance	**2,457**	2,072	1,935
Depreciation, decommissioning and amortization	**860**	882	780
Property and other taxes	**177**	168	117
Net gain on sale of utility plant	**—**	(5)	(5)
Total operating expenses	**6,435**	7,276	6,588
Operating income	**2,013**	1,578	2,118
Interest and dividend income	**20**	100	262
Other nonoperating income	**84**	72	75
Interest expense – net of amounts capitalized	**(409)**	(457)	(584)
Other nonoperating deductions	**(69)**	(23)	18
Income from continuing operations before tax and minority interest	**1,639**	1,270	1,889
Income tax	**438**	388	642
Minority interest	**280**	—	—
Income from continuing operations	**921**	882	1,247
Income from discontinued operations – net of tax	**—**	50	—
Net income	**921**	932	1,247
Dividends on preferred stock subject to mandatory redemption	**—**	5	13
Dividends on preferred stock not subject to mandatory redemption	**6**	5	6
Net income available for common stock	**$ 915**	$ 922	$ 1,228

Consolidated Statements of Comprehensive Income

In millions Year ended December 31,	**2004**	2003	2002
Net income	**$ 921**	$ 932	$ 1,247
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment	**(1)**	(4)	(5)
Amortization of cash flow hedges	**3**	1	11
Comprehensive income	**$ 923**	$ 929	$ 1,253

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

Consolidated Balance Sheets

In millions December 31,	2004	2003
ASSETS		
Cash and equivalents	**$ 122**	$ 95
Restricted cash	**61**	66
Receivables, less allowances of $31 and $30 for uncollectible accounts at respective dates	**618**	602
Accrued unbilled revenue	**320**	273
Fuel inventory	**8**	10
Materials and supplies	**188**	168
Accumulated deferred income taxes – net	**134**	563
Regulatory assets	**553**	299
Prepayments and other current assets	**72**	62
Total current assets	**2,076**	2,138
Nonutility property – less accumulated provision for depreciation of $34 and $24 at respective dates	**583**	116
Property of variable interest entities – net	**377**	—
Nuclear decommissioning trusts	**2,757**	2,530
Other investments	**170**	150
Total investments and other assets	**3,887**	2,796
Utility plant, at original cost:		
Transmission and distribution	**15,685**	14,861
Generation	**1,356**	1,388
Accumulated provision for depreciation	**(4,506)**	(4,386)
Construction work in progress	**789**	601
Nuclear fuel, at amortized cost	**151**	141
Total utility plant	**13,475**	12,605
Regulatory assets	**3,285**	3,725
Other deferred charges	**567**	507
Total deferred charges	**3,852**	4,232
Total assets	**$ 23,290**	$ 21,771

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

In millions, except share amounts December 31,	2004	2003
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**$ 88**	$ 200
Long-term debt due within one year	**246**	371
Preferred stock to be redeemed within one year	**9**	9
Accounts payable	**700**	497
Accrued taxes	**357**	476
Accrued interest	**115**	107
Customer deposits	**168**	152
Book overdrafts	**232**	189
Regulatory liabilities	**490**	659
Other current liabilities	**643**	972
Total current liabilities	**3,048**	3,632
Long-term debt	**5,225**	4,121
Accumulated deferred income taxes – net	**2,865**	2,726
Accumulated deferred investment tax credits	**126**	136
Customer advances and other deferred credits	**510**	428
Power-purchase contracts	**130**	213
Preferred stock subject to mandatory redemption	**139**	141
Accumulated provision for pensions and benefits	**417**	330
Asset retirement obligations	**2,183**	2,084
Regulatory liabilities	**3,356**	3,234
Other long-term liabilities	**232**	242
Total deferred credits and other liabilities	**9,958**	9,534
Total liabilities	**18,231**	17,287
Commitments and contingencies (Notes 2, 9 and 10)		
Minority interest	**409**	—
Common stock (434,888,104 shares outstanding at each date)	**2,168**	2,168
Additional paid-in capital	**350**	338
Accumulated other comprehensive loss	**(17)**	(19)
Retained earnings	**2,020**	1,868
Total common shareholder's equity	**4,521**	4,355
Preferred stock not subject to mandatory redemption	**129**	129
Total shareholders' equity	**4,650**	4,484
Total liabilities and shareholders' equity	**$ 23,290**	$ 21,771

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

Consolidated Statements of Cash Flows

In millions Year ended December 31,	2004	2003	2002
Cash flows from operating activities:			
Income from continuing operations	**$ 921**	$ 882	$ 1,247
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**860**	882	780
Other amortization	**90**	101	106
Minority interest	**280**	—	—
Deferred income taxes and investment tax credits	**514**	(104)	(640)
Regulatory assets – long-term	**442**	535	(6,738)
Regulatory liabilities – long-term	**(69)**	(48)	8,589
Other assets	**(77)**	122	98
Other liabilities	**18**	(364)	135
Receivables and accrued unbilled revenue	**(9)**	185	480
Inventory, prepayments and other current assets	**(10)**	78	(86)
Regulatory assets – short-term	**(254)**	13,268	(1,252)
Regulatory liabilities – short-term	**(169)**	(12,486)	876
Accrued interest and taxes	**(111)**	(223)	(191)
Accounts payable and other current liabilities	**(152)**	(181)	(2,856)
Net cash provided by operating activities	**2,274**	2,647	548
Cash flows from financing activities:			
Long-term debt issued and issuance costs	**1,747**	(11)	(32)
Long-term debt repaid	**(966)**	(1,263)	(1,200)
Bonds remarketed – net	**350**	—	191
Redemption of preferred stock	**(2)**	(6)	(100)
Rate reduction notes repaid	**(246)**	(246)	(246)
Nuclear fuel financing – net	**—**	—	(59)
Short-term debt financing – net	**(112)**	(4)	(527)
Change in book overdrafts	**43**	65	77
Shares purchased for stock-based compensation	**(60)**	(13)	(3)
Proceeds from stock option exercises	**29**	3	—
Minority interest	**(290)**	—	—
Dividends paid	**(756)**	(955)	(40)
Net cash used by financing activities	**(263)**	(2,430)	(1,939)
Cash flows from investing activities:			
Capital expenditures	**(1,678)**	(1,153)	(1,037)
Acquisition costs related to nonutility generation plant	**(285)**	—	—
Proceeds from sale of discontinued operations	**—**	146	—
Contributions to and earnings from nuclear decommissioning trusts – net	**(109)**	(86)	(12)
Sales of investments in other assets	**9**	13	18
Net cash used by investing activities	**(2,063)**	(1,080)	(1,031)
Effect of consolidation of variable interest entities	**79**	—	—
Net change in cash of discontinued operations	**—**	(34)	—
Net increase (decrease) in cash and equivalents	**27**	(897)	(2,422)
Cash and equivalents, beginning of year	**95**	992	3,414
Cash and equivalents, end of year–continuing operations	**$ 122**	$ 95	$ 992

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

Consolidated Statements of Changes in Common Shareholder's Equity

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholder's Equity
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 cash flow hedges			4		4
Tax effect			7		7
Dividends accrued on preferred stock subject to mandatory redemption				(13)	(13)
Dividends accrued on preferred stock not subject to mandatory redemption				(6)	(6)
Shares purchased for stock-based compensation		(3)			(3)
Non-cash stock-based compensation		8			8
Capital stock expense and other		(1)			(1)
Balance at December 31, 2002	$ 2,168	$ 340	$ (16)	$ 1,892	$ 4,384
Net income				932	932
Minimum pension liability adjustment			(7)		(7)
Tax effect			3		3
Amortization of cash flow hedges			2		2
Tax effect			(1)		(1)
Dividends declared on common stock				(945)	(945)
Dividends declared on preferred stock subject to mandatory redemption				(5)	(5)
Dividends declared on preferred stock not subject to mandatory redemption				(5)	(5)
Shares purchased for stock-based compensation		(9)		(4)	(13)
Proceeds from stock option exercises				3	3
Non-cash stock-based compensation		5			5
Capital stock expense and other		2			2
Balance at December 31, 2003	$ 2,168	$ 338	$ (19)	$ 1,868	$ 4,355
Net income				921	921
Minimum pension liability adjustment			(1)		(1)
Amortization of cash flow hedges			5		5
Tax effect			(2)		(2)
Dividends declared on common stock				(750)	(750)
Dividends declared on preferred stock not subject to mandatory redemption				(6)	(6)
Shares purchased for stock-based compensation		(17)		(43)	(60)
Proceeds from stock option exercises				29	29
Non-cash stock-based compensation		30			30
Capital stock expense and other		(1)		1	—
Balance at December 31, 2004	$ 2,168	$ 350	$ (17)	$ 2,020	$ 4,521

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

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

Certain prior-period amounts were reclassified to conform to the December 31, 2004 financial statement presentation.

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and Notes. Actual results could differ from those estimates. Certain significant estimates related to regulatory matters, financial instruments, income taxes, pensions 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.

Business Segments

SCE's reportable business segments include the rate-regulated electric utility segment and the VIE segment. The VIEs were consolidated as of March 31, 2004. Electric utility segment revenue was $8.2 billion in 2004. Electric utility segment assets were $22.8 billion as of December 31, 2004. Electric utility income was 100% of SCE's net income in 2004. Additional details on the VIE segment are shown under the heading "Variable Interest Entities" in this Note. The VIEs are gas-fired power plants that sell both electricity and steam. The VIE segment consists of non-rate-regulated entities. SCE's management has no control over the resources allocated to the VIE segment and does not make decisions about its performance.

Cash Equivalents

Cash equivalents include other investments of $64 million at December 31, 2003 with original maturities of three months or less. There were no cash equivalents at December 31, 2004. Additionally, at December 31, 2004, the VIE segment had $90 million in cash and equivalents. 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.

Dividend Restriction

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. SCE's authorized capital structure includes a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2004, SCE's 13-month weighted-average common equity component of total capitalization was 50.5%. At December 31, 2004, SCE had the capacity to pay $222 million in additional dividends based on the 13-month weighted-average method. Based on recorded December 31, 2004 balances, SCE's common equity to total capitalization ratio was 50.4% for ratemaking purposes. SCE had the capacity to pay $213 million of additional dividends to Edison International based on December 31, 2004 recorded balances.

Inventory

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

New Accounting Principles

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. SCE currently uses the intrinsic value accounting method for stock-based compensation. SCE will adopt the new method effective July 1, 2005. The difference in expense between the two methods is shown in Note 1 under "Stock-Based Compensation." SCE is reviewing the new standard and has not yet selected a transition method for adoption of the new standard.

In December 2004, the Financial Accounting Standards Board (FASB) issued guidance (Staff Position 109-1) on accounting for a tax deduction resulting from the American Jobs Creation Act of 2004. The primary objective of this Position is to provide guidance on accounting for the provision within the American Jobs Creation Act of 2004 that provides a tax deduction on qualified production activities. Under this Position, recognition of the tax deduction on qualified production activities, which include the production of electricity, is reported in the year it is earned. This FASB Staff Position had no material impact on SCE's financial statements. SCE is evaluating the effect that the manufacturer's deduction will have in subsequent years.

In December 2003, the FASB issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of VIEs. The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, VIEs, where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE unless specific exceptions apply. This Interpretation was 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.

SCE has 270 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 under terms and pricing controlled by the CPUC. SCE conducted a review of its QF contracts and determined that SCE has variable interests in 12 contracts with gas-fired cogeneration plants that are potential VIEs and that contain variable pricing provisions based on the price of natural gas and for which SCE does not have sufficient information to determine if the projects qualify for a scope exception. SCE requested from the entities that hold these contracts the financial information necessary to determine whether SCE must consolidate these projects. All 12 entities declined to provide SCE with the necessary financial information. However, four of the 12 contracts are with entities 49%–50% owned by a related party, Edison Mission Energy (EME). EME is an indirect wholly owned subsidiary of SCE's parent company, Edison International. Although the four related-party entities have declined to provide their financial information to SCE, Edison International has access to such information and has provided combined financial statements to SCE. SCE has determined that it must consolidate the four power projects partially owned by EME based on a qualitative analysis of the facts and circumstances of the entities, including the related-party nature of the transaction. SCE will continue to attempt to obtain information for the other eight projects in order to determine whether they should be consolidated by SCE.

The remaining 258 contracts will not be consolidated by SCE under the new accounting standard, since SCE lacks a variable interest in these contracts or the contracts are with governmental agencies, which are generally excluded from the standard.

SCE analyzes its potential variable interests by calculating operating cash flows. A fixed-price contract to purchase electricity from a power plant does not transfer sufficient risk to SCE to be considered a variable interest. A contract with a non-natural-gas-fired plant that is based on the price of natural gas is also not a variable interest. SCE has other power contracts with non-QF generators. SCE has determined that these contracts are not significant variable interests.

See "Variable Interest Entities" for further information.

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. These items were previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on these instruments were included in interest expense – net of amounts capitalized on SCE's consolidated statements of income. Prior period financial statements were 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 preferred stock in Note 3.

Nuclear

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

SCE's nuclear plant investments made prior to the return to cost-of-service ratemaking are recorded as regulatory assets on its balance sheets. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the rate-making treatment for these assets.

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	**2004**	2003	2002
Property condemnation settlement	**$ —**	$ —	$ 38
Allowance for funds used during construction	**35**	27	19
Performance-based incentive awards	**31**	21	—
Other	**18**	24	18
Total other nonoperating income	**$ 84**	$ 72	$ 75
Provisions for regulatory issues and refunds	**$ —**	$ —	$ (42)
Various penalties	**35**	—	—
Other	**34**	23	24
Total other nonoperating deductions	**$ 69**	$ 23	$ (18)

Planned Major Maintenance

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

Property and Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. 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 3.9% for 2004, 4.3% for 2003 and 4.2% for 2002.

AFUDC – equity was $23 million in 2004, $21 million in 2003 and $11 million in 2002. AFUDC – debt was $12 million in 2004, $6 million in 2003 and $8 million in 2002.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for asset retirement obligations.

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
Nonutility property	5 years to 60 years
Other plant	5 years to 40 years

SCE's net investment in generation-related utility plant was $920 million at December 31, 2004 and $867 million at December 31, 2003.

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

Nonutility property, including construction in progress, is capitalized at cost, including interest accrued on borrowed funds that finance construction. Capitalized interest was $9 million in 2004, zero in 2003 and $1 million in 2002. The Mountainview power plant is included in nonutility property in accordance with the rate-making treatment.

As a result of an accounting standard adopted in 2003, SCE recorded the fair value of its liability for legal asset retirement obligations (ARO), which was primarily related to the decommissioning of its nuclear power facilities. In addition, SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Prior to this standard, SCE had recorded these amounts in accumulated provision for depreciation and decommissioning. SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates; therefore, implementation of this new standard did not affect earnings.

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

In millions	
Initial ARO liability as of January 1, 2003	$ —
Adoption of new standard	2,024
Accretion expense	128
Liabilities settled	(68)
ARO liability as of December 31, 2003	2,084
Accretion expense	132
Liabilities settled	(33)
ARO liability as of December 31, 2004	$ 2,183
Fair value of nuclear decommissioning trusts	$ 2,757

Purchased Power

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

Receivables

SCE records an allowance for uncollectible accounts, as determined by the average percentage of revenue not collected in prior accounting periods. SCE assesses its customers a late fee of 0.9% per month, beginning 19 days after the bill is prepared. Inactive accounts are written off after 180 days.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future recovery of certain costs from customers through the rate-making process, and regulatory liabilities, which represent probable future credits to customers through the rate-making process.

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

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

Regulatory Assets

Regulatory assets included in the consolidated balance sheets are:

In millions December 31,	2004	2003
Current:		
Regulatory balancing accounts	**$ 371**	$ 140
Direct access procurement charges	**109**	90
Purchased-power settlements	**62**	57
Other	**11**	12
	553	299
Long-term:		
Flow-through taxes – net	**1,018**	974
Rate reduction notes – transition cost deferral	**739**	985
Unamortized nuclear investment – net	**526**	583
Nuclear-related ARO investment – net	**272**	288
Unamortized coal plant investment – net	**78**	66
Unamortized loss on reacquired debt	**250**	222
Direct access procurement charges	**141**	250
Environmental remediation	**55**	71
Purchased-power settlements	**91**	153
Other	**115**	133
	3,285	3,725
Total Regulatory Assets	**$ 3,838**	$ 4,024

SCE's regulatory assets related to direct access procurement charges are for amounts direct access customers owe bundled service customers for the period May 1, 2000 through August 31, 2001, and are offset by corresponding regulatory liabilities to the bundled service customers. These amounts will be collected by mid-2007. SCE's regulatory assets related to purchased-power settlements will be recovered through 2008. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to flow-through taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory asset related to the rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and is expected to be recovered by the end of 2007. SCE's nuclear-related regulatory assets are expected to be recovered by the end of the remaining useful lives of the nuclear facilities. SCE has requested a four-year recovery period for the net regulatory asset related to its unamortized coal plant investment. CPUC approval is pending. SCE's regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from 1 year to 31 years. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

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

Regulatory Liabilities

Regulatory liabilities included in the consolidated balance sheets are:

In millions December 31,	2004	2003
Current:		
Regulatory balancing accounts	**$ 357**	$ 549
Direct access procurement charges	**109**	90
Other	**24**	20
	490	659
Long-term:		
ARO	**819**	720
Costs of removal	**2,112**	2,020
Direct access procurement charges	**141**	250
Employee benefits plans	**200**	207
Other	**84**	37
	3,356	3,234
Total Regulatory Liabilities	**$ 3,846**	$ 3,893

SCE's regulatory liability related to the ARO represents timing differences between the recognition of nuclear decommissioning obligations in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent revenue collected for asset removal costs that SCE expects to incur in the future. Historically, these removal costs have been recorded in accumulated depreciation; however, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. SCE's regulatory liabilities related to direct access procurement charges are a liability to its bundled service customers and are offset by regulatory assets from direct access customers. SCE's regulatory liabilities related to employee benefit plan expenses represent pension and postretirement benefits other than pensions costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will either be returned to ratepayers in some future rate-making proceeding, or be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process.

Related Party Transactions

Four EME 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. Beginning March 31, 2004, SCE consolidates these projects (see "Variable Interest Entities").

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

Restricted Cash

SCE's restricted cash represents amounts used exclusively to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity.

Revenue

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

Since January 17, 2001, power purchased by the CDWR or through the California Independent System Operator (ISO) for SCE's customers is not considered a cost to SCE, because SCE is acting as an agent for these transactions. Further, amounts billed to ($2.5 billion in 2004, $1.7 billion in 2003 and $1.4 billion in 2002) 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 Compensation

SCE has stock-based 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 compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income if SCE had used the fair-value accounting method.

In millions Year ended December 31,	**2004**	2003	2002
Net income available for common stock, as reported	**$ 915**	$ 922	$ 1,228
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	**28**	7	7
Less: stock-based compensation expense using the fair-value accounting method – net of tax	**32**	9	5
Pro forma net income available for common stock	**$ 911**	$ 920	$ 1,230

Supplemental Accumulated Other Comprehensive Loss Information

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

In millions December 31,	2004	2003
Minimum pension liability – net	$ (10)	$ (9)
Unrealized losses on cash flow hedges – net	(7)	(10)
Accumulated other comprehensive loss	**$ (17)**	$ (19)

The minimum pension liability is discussed in Note 7, 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 $7 million (as of December 31, 2004, 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 2005.

Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions Year ended December 31,	2004	2003	2002
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	$ 342	$ 390	$ 487
Tax payments	29	585	1,110
Non-cash investing and financing activities:			
Details of consolidation of variable interest entities:			
Assets	$ 458	—	—
Liabilities	(537)	—	—
Reoffering of pollution-control bonds	$ 196	—	—
Details of pollution-control bonds redemption:			
Release of funds held in trust	$ 20	—	—
Pollution-control bonds redeemed	(20)	—	—
Details of debt exchange:			
Retirement of senior secured credit facility	$ —	$ (700)	—
Short-term credit facility utilized	—	200	—
Cash paid	—	(500)	—
Details of long-term debt exchange offer:			
Variable rate notes redeemed	$ —	$ (966)	—
First and refunding mortgage bonds issued	—	966	—
Obligation to fund investment in acquisition	$ —	8	—
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)

Variable Interest Entities

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Further, four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts have 20-year terms. The QFs sell electricity to SCE and steam to nonrelated parties. Under a new accounting standard, SCE consolidated these four projects effective March 31, 2004. Prior periods have not been restated.

Project	Capacity	Termination Date	EME Ownership
Kern River	300 MW	August 2005	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any profit or loss generated by these entities will not effect SCE's income statement, except that SCE would be required to recognize losses if these projects have negative equity in the future. These losses, if any, would not affect SCE's liquidity. Any liabilities of these projects are non-recourse to SCE.

SCE has no controlling ownership interest in the four entities that have been consolidated under the new accounting Interpretation and has no legal or contractual rights to compel these entities to provide information to SCE. As a result, SCE has no legal, contractual or other right to design, establish, maintain or evaluate the effectiveness of internal controls over financial reporting for these consolidated variable interest entities. Accordingly, SCE did not include these variable interest entities in its conclusion regarding internal controls over financial reporting.

The variable interest entities' operating costs, instead of purchased power expense, are shown in SCE's income statements effective April 1, 2004. Further, SCE's operating revenue now includes revenue from the sale of steam by these four projects. The table below shows the effect on SCE's consolidated statement of income now that these variable interest entities are consolidated.

In millions Year ended December 31,	2004
Operating revenue	**$ 285**
Fuel	**578**
Purchased power	**(669)**
Other operation and maintenance	**68**
Depreciation, decommissioning and amortization	**28**
Total operating expenses	**5**
Operating income	**280**
Minority interest	**(280)**
Income from continuing operations	**$ —**

The table below shows the effect on SCE's consolidated balance sheet now that these variable interest entities are consolidated.

In millions December 31,	2004
ASSETS	
Cash	$ 90
Accounts receivable – net	49
Other current assets	18
Nonutility property – less accumulated provision for depreciation of $519	377
Deferred charges	5
Total assets	**$ 539**
LIABILITIES AND SHAREHOLDER'S EQUITY	
Accounts payable	$ 62
Other current liabilities	2
Long-term debt (5.0%, due 2008)	54
Deferred credits	12
Minority interest	409
Total liabilities and shareholder's equity	**$ 539**

As noted under New Accounting Principles, SCE also has eight other contracts with certain QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under the new accounting standard. However, these entities are not legally obligated to provide the financial information to SCE that is necessary to determine whether SCE must consolidate these entities. These eight entities have declined to provide SCE with the necessary financial information. SCE will continue to attempt to obtain information for these projects in order to determine whether they should be consolidated by SCE. The aggregate capacity dedicated to SCE for these projects is 267 MW. SCE paid $166 million in 2004 to these projects. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

Note 2. 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. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) (collectively, the investor-owned utilities). Amounts billed to SCE's customers for electric power purchased and sold by the CDWR (approximately $2.5 billion in 2004) are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings.

In December 2004, the CPUC issued its decision on how the CDWR's power charge revenue requirement for 2004 through 2013, when the last CDWR contract expires, will be allocated among the investor-owned utilities. The CPUC rejected a settlement agreement among PG&E, the Utility Reform Network (TURN), and SCE and which the ORA supported. However, the CPUC's final decision adopts key attributes of that settlement agreement. It adopts a cost-follows-contract allocation to each of the investor-owned utilities of the unavoidable portion of costs incurred under CDWR contracts. A previous CPUC decision allocated the avoidable portion of the costs on a cost-follows-contract basis. Allocating the avoidable and unavoidable portions on a cost-follows-contract basis provides the investor-owned utilities the appropriate incentives to operate and administer the contracts that have been allocated to them. In addition, in order to fairly allocate the total burden of the CDWR contracts among the investor-owned utilities, the decision adjusts the cost-follows-contract allocation of the total costs (avoidable and unavoidable) such that the above-market cost burden associated with the contracts is allocated as follows: 44.8% to PG&E's customers, 45.3% to SCE's customers, and 9.9% to SDG&E's customers. The CPUC's December 2004 decision is based on the above market cost analysis that SCE presented in its initial testimony in December 2003.

In response to an application filed by SDG&E, the CPUC issued an order granting limited rehearing of the December 2004 decision. The rehearing permits parties to present alternative methodologies and updated data for the calculation of above market costs associated with the CDWR contracts. A schedule has not been adopted for the rehearing, but it is expected to take place in the second quarter of 2005.

SDG&E has also filed a petition for modification of the decision urging the CPUC to replace the adopted methodology with a methodology that would retain the cost-follows-contract allocation of the avoidable costs, but would allocate the unavoidable costs associated with the contracts: 42.2% to PG&E's customers, 47.5% to SCE's customers, and 10.3% to SDG&E's customers. Such an allocation would decrease the total costs allocated to SDG&E's customers and increase the total costs allocated to SCE's customers. The CPUC is expected to act on the petition in March 2005.

CPUC Litigation Settlement Agreement

In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC which sought full recovery of its electricity procurement costs incurred during the energy crisis. A key element of the 2001 CPUC settlement agreement was the establishment of a regulatory balancing account, called the Procurement-Related Obligations Account (PROACT), which was fully recovered by August 2003.

Energy Resource Recovery Account Proceedings

In an October 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). 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.

ERRA Reasonableness Review for the Period September 1, 2001 through June 30, 2003

On October 3, 2003, SCE submitted its first ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. The CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA recommended disallowances that totaled approximately $14 million of costs recovered through the PROACT mechanism during the period from September 1, 2001 through June 30, 2003. In April 2004, SCE reached an agreement with the ORA (subject to CPUC approval) to reduce the PROACT disallowances to approximately $4 million. On January 27, 2005, the CPUC issued a decision approving the agreement. The $4 million, which is mainly comprised of ISO grid management charges and employee-related retraining costs, will be refunded to ratepayers through a credit to the ERRA.

The January 27, 2005 CPUC decision also provides that SCE's administration of its procurement contracts will be subject to reasonableness review under the "reasonable manager" standard. However, the CPUC decision provides that the review of SCE's daily dispatch of its generation resources will be subject to a compliance review, not a reasonableness review, and will only include a review of spot market transactions in the day-ahead, hour-ahead and real-time markets. The decision found that SCE's daily dispatch decisions during the record period complied with the CPUC's standard, and that its administration of its contracts was reasonable in all respects. It authorized recovery of amounts paid to Peabody Coal Company for costs associated with the Mohave mine closing as well as transmission costs related to serving municipal utilities, and also resolved outstanding issues from 2000 and 2001 related to CDWR costs. As a result of this decision, SCE recorded a pre-tax net regulatory gain of $118 million in 2004.

ERRA Reasonableness Review for the Period July 1, 2003 through December 31, 2003

On April 1, 2004, SCE submitted its second ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from July 1, 2003 through December 31, 2003, to be reasonable. In addition, SCE requested recovery of a $10 million reward for Palo Verde Unit 3 efficient operation and $5 million in electric energy transaction administration costs.

On January 17, 2005, the CPUC issued a decision finding that SCE's administration of its power purchase agreements and its daily decisions dispatching its procurement resources were reasonable and prudent. The decision also found that the revenue and expenses recorded in SCE's ERRA account during the record period were reasonable and prudent, and approved SCE's requested recovery of the items discussed above.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its net-short position (expected load requirements exceed generation supply) 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. Currently, the CPUC and the California Energy Commission are working together to set rules for various aspects of generation procurement which are described below.

Procurement Plan

<u>Resource Planning Component of the Procurement Plan</u>

On April 1, 2004, the CPUC instituted a resource planning proceeding that, among other things, will coordinate consideration of long-term resource plans. On July 9, 2004, SCE filed testimony on its long-term procurement plan, which includes a substantial commitment to cost-effective energy efficiency and an advanced load-control program. A CPUC decision approving SCE's long-term procurement plan was issued in December 2004. The decision required all long-term procurement to be conducted through all-source solicitations; allowed the consideration of debt equivalence in the bid evaluation process; and required the use of a greenhouse gas adder as a bid evaluation component. The decision also extended the utilities' authority to procure longer-term products and lifted the affiliate ban on long-term power products. SCE's next long-term procurement plan will be filed in 2006.

Assembly Bill 57 Component of the Procurement Plan

In December 2003, the CPUC adopted a 2004 short-term 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. Currently, SCE is operating under this approved short-term procurement plan. To the extent SCE procures power in accordance with the plan, SCE receives full-cost recovery of its procurement transactions pursuant to Assembly Bill 57. Accordingly, the plan is referred to as the Assembly Bill 57 component of the procurement plant.

Each quarter, SCE is required to file a report with the CPUC demonstrating that SCE's procurement-related transactions associated with serving the demands of its bundled electricity customers were in conformance with SCE's adopted short-term procurement plan. SCE has submitted seven quarterly compliance filings covering the period from January 1, 2003 through September 30, 2004, including its third quarter 2004 compliance filing on November 1, 2004. To date, however, the CPUC has only issued one resolution approving SCE's first compliance report for the period January 1, 2003 to March 31, 2003. While SCE believes that all of its procurement transactions were in compliance with its adopted short-term procurement plan, SCE cannot predict with certainty whether or not the CPUC will agree with SCE's interpretation regarding some elements.

Resource Adequacy Requirements

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. On October 28, 2004, the CPUC issued a decision clarifying the January 2004 decision. The October 2004 decision requires load-serving entities to ensure that adequate resources have been contracted to meet that entity's peak forecasted energy resource demand and an additional planning reserve margin of 15-17% of that peak load by June 1, 2006. Currently, the decision requires SCE to demonstrate that it has contracted 90% of its May–September 2006 resource adequacy requirement by September 30, 2005. As the May–September period approaches, SCE will be required to fill out the remaining 10% of its resource adequacy requirement one month in advance of expected need. The October 28, 2004 decision also clarified that although the first compliance filing will only cover May–September 2006, the 15–17% planning reserve margin is a year-round requirement. In its October 2004 decision, the CPUC also decided that long-term CDWR contracts allocated to the investor-owned utilities during the 2001 energy crisis are to be fully counted for resource adequacy purposes, and that deliverability standards developed during subsequent phases will be applied to such contracts. These deliverability standards, as well as a wide range of other issues, including scheduling and load forecasting, will be addressed in a separate phase of the proceeding which is expected to be completed by mid-2005. SCE expects to meet its resource adequacy requirements by the deadlines set forth in the decision.

Avoided Cost Proceeding

SCE purchases electric energy and capacity from various QFs pursuant to contracts that provide for payment at avoided cost, as determined by the CPUC. On April 22, 2004, the CPUC opened a rulemaking to develop, review and update methodologies for determining avoided costs, including the methodologies SCE uses to pay its QFs. Among other things, the rulemaking is to consider modifications to the current methodology for short-run avoided cost energy pricing and the current as-available capacity pricing. The rulemaking also proposes to develop a long-run avoided cost pricing methodology for QFs. Hearings are scheduled for May 2005. Although the rulemaking may affect the amounts paid to QFs and customer rates, changes to pricing methodology should not affect SCE's earnings as such costs are recovered from ratepayers, subject to reasonableness review.

Extension of QF Contracts and New QF Contracts

SCE has 270 power-purchase contracts with QFs, a number of which will expire in the next five years. On September 30, 2004, the CPUC issued a ruling requesting proposals and comments on the development of a long-term policy for expiring QF contracts and new QFs. SCE filed its response to the ruling on November 10, 2004, in which it proposed to purchase electricity from QFs by (1) allowing QFs to compete in SCE's competitive solicitations; (2) conducting bilateral negotiations for new contracts or contract extensions with QFs; or (3) offering an energy-only contract at market-based avoided cost prices. Hearings are scheduled for May 2005.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, and 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. At year-end 2004, SCE obtained approximately 18% of its power supplies from renewable resources. 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. In June 2004, the CPUC issued two decisions adopting additional rules on renewable procurement: a decision adopting standard contract terms and conditions and a decision adopting a market-price methodology. In July 2004, the CPUC issued a decision adopting criteria for the selection of least-cost and best-fit renewable resources. In December 2004, an assigned commissioner's ruling and scoping memo was issued establishing a schedule for addressing various renewable procurement-related issues that were not resolved by prior rulings and decision and directing the utilities to file renewable procurement plans addressing their 2005 renewable procurement goals and a plan for renewable procurement over the period 2005–2014. SCE's 2005 renewable procurement plan was filed on March 7, 2005.

SCE received bids for renewable resource contracts in response to a solicitation it made in August 2003 and conducted negotiations with bidders regarding potential procurement contracts. On March 8, 2005, SCE filed an advice letter with the CPUC requesting approval of 6 renewable contracts. SCE expects a CPUC decision on its advice letter by the second quarter of 2005. The procedures for measuring renewable procurement are still being developed by the CPUC. Based upon the current regulatory framework, SCE anticipates that it will comply, even without new renewable procurement contracts, with renewable procurement mandates through at least 2005. Beyond 2005, SCE will either need to sign new contracts and/or extend existing renewable QF contracts.

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.

On January 28, 2005, the CPUC opened a new phase of its procurement proceeding to consider the reallocation of certain CDWR contracts. Evidentiary hearings may be held later this year.

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 May 21, 2004, the Court of Appeal issued its decision in the two consolidated cases, and denied the utilities' and their holding companies' challenges to both CPUC decisions. The Court of Appeal held that the CPUC has limited jurisdiction to enforce in a CPUC proceeding the conditions agreed to by holding companies incident to their being granted authority to assume ownership of a CPUC-regulated utility. The Court of Appeal held that the CPUC's decision interpreting the first priority requirement was not reviewable because the CPUC had not made any ruling that any holding company had violated the first priority requirement. However, the Court of Appeal suggested that if the CPUC or any other authority were to rule that a utility or holding company violated the first priority requirement, the utility or holding company would be permitted to challenge both the finding of violation and the underlying interpretation of the first priority requirement itself. On June 30, 2004, Edison International and the other utility holding companies filed with the California Supreme Court a petition for review of the Court of Appeal decision as to jurisdiction over holding companies, but they and the utilities did not file a challenge to the decision as to the first priority issue. On September 1, 2004, the California Supreme Court denied the petition for review. The Court of Appeal's decision, as to jurisdiction, is now final.

The original order instituting the investigation into whether the utilities and their holding companies have complied with CPUC decisions and applicable statutes remains in effect. However, on February 11, 2005, an administrative law judge ruling was issued which provides that any party to the proceedings that believes the proceedings should remain open has 30 days to file comments listing matters that remain to be decided and explaining why they must be resolved at the CPUC rather than in another forum. The CPUC indicated that if comments are not received in the 30 day time period, a decision closing the proceeding will be prepared for CPUC consideration and no further comment will be allowed. At this time, SCE is not aware whether or not comments have been received or whether the CPUC has taken further action.

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 any 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 enhanced pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

On December 2, 2004 the CPUC issued a final decision on the application. Principally, the decision: (1) directs SCE to continue the ongoing negotiations and other efforts toward resolving the post-2005 coal and water supply issues; (2) directs SCE to conduct a study of potential generation resources that might serve as alternatives or complements to Mohave including solar generation and coal gasification; (3) provides an opportunity for SCE to recover in future rates certain Mohave-related costs that SCE has already incurred or is expected to incur by 2006, including certain preliminary engineering costs, water study costs and the costs of the study of potential Mohave alternatives; and (4) authorizes SCE to establish a rate-making account to track certain worker protection-related costs that might be incurred in 2005 in preparation for a temporary or permanent Mohave shutdown after 2005.

In parallel with the CPUC proceeding, negotiations have continued among the relevant parties in an effort to resolve the coal and water supply issues. Since November 2004, the parties have engaged in negotiations facilitated by a professional mediator, but no final resolution has been reached. In addition, agencies of the federal government are now conducting both a hydro-geological study and an environmental review regarding a possible alternative groundwater source for the slurry water; these studies, projected to cost approximately $6 million, are being funded by SCE and the other Mohave co-owners subject to the terms and conditions of a 2004 memorandum of understanding among the Mohave co-owners, the Tribes and the federal government.

The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but the presence or absence of Mohave as an available resource beyond 2005 will impact SCE's long-term resource plan. The outcome of this matter is not expected to have a material impact on earnings.

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

In light of the issues discussed above, in 2002 SCE concluded that it was probable Mohave would be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million in 2002. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded in regulatory assets as a long-term receivable to be collected from customer revenue. This treatment was based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates (together with a reasonable return) through a balancing account mechanism, as presented in its May 17, 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 California Power Exchange and ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets. Under the 2001 CPUC settlement agreement, mentioned in "CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE net of costs will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company (El Paso) entered into a settlement agreement with a number of parties (including SCE, PG&E, the State of California and various consumer class action representatives) settling various claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso 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 United States District Court has issued an order approving the stipulated judgment and the settlement agreement has become effective. Pursuant to a CPUC decision, SCE will refund to customers amounts received under the terms of the El Paso settlement (net of legal and consulting costs) through its ERRA mechanism. In June 2004, SCE received its first settlement payment of $76 million. Approximately $66 million of this amount was credited to purchased-power expense, and will be refunded to SCE's ratepayers through the ERRA over the next 12 months, and the remaining $10 million was used to offset SCE's incurred legal costs. Additional settlement payments totaling approximately $127 million are due from El Paso over a 20-year period. As a result, SCE recorded a receivable and corresponding regulatory liability of $65 million in 2004 for the discounted present value of the future payments (discounted at an annual rate of 7.86%). Amounts El Paso refunds to the CDWR will result in reductions in the CDWR's revenue requirement allocated to SCE in proportion to SCE's share of the CDWR's power charge revenue requirement.

On July 2, 2004, the FERC approved a settlement agreement between SCE, SDG&E and PG&E and The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds and other payments to the settling purchasers and others against some of Williams' power charges in 2000–2001. In August 2004, SCE received its $37 million share of the refunds and other payments under the Williams settlement.

On April 26, 2004, SCE, PG&E, SDG&E and several California state governmental entities agreed to settlement terms with West Coast Power, LLC and its owners, Dynegy Inc. and NRG Energy, Inc.

(collectively, Dynegy). The settlement terms provide for refunds and other payments totaling $285 million, with a proposed allocation to SCE of approximately $42 million. The Dynegy settlement terms were approved by the FERC on October 25, 2004 and SCE received its $42 million share of the settlement proceeds in November 2004.

On July 12, 2004, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Duke Energy Corporation and a number of its affiliates (collectively Duke). The settlement terms agreed to with the Duke parties provide for refunds and other payments totaling in excess of $200 million, with a proposed allocation to SCE of approximately $45 million. The Duke settlement was approved by the FERC on December 7, 2004 and SCE received its $45 million share of the settlement proceeds in January 2005.

On January 14, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in a Chapter 11 bankruptcy proceeding pending in Texas. Among other things, the settlement terms provide for expected cash and equivalent refunds totaling $320 million, of which SCE's allocated share is approximately $68 million. The settlement also provides for an allowed, unsecured claim totaling $175 million in the bankruptcy of one of the Mirant parties, with SCE being allocated approximately $33 million of the unsecured claim. The actual value of the unsecured claim will be determined as part of the resolution of the Mirant parties' bankruptcies. The Mirant settlement was submitted to the FERC for its approval on January 31, 2005 and was submitted to the Mirant bankruptcy court for its approval on February 23, 2005.

On November 19, 2004, the CPUC issued a resolution authorizing SCE to establish an Energy Settlement Memorandum Account (ESMA) for the purpose of recording the foregoing settlement proceeds from energy providers and allocating them in accordance with the terms of the CPUC litigation settlement agreement. The resolution accordingly provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA will be allocated to recovery of SCE's litigation costs and expenses in the FERC refund proceedings described above and as a shareholder incentive pursuant to the CPUC litigation settlement agreement. Remaining amounts for each settlement are to be refunded to ratepayers through the ERRA mechanism. In 2004, SCE recorded in the caption "Other nonoperating income" on the income statement a total of $12 million as shareholder incentives related to refunds received in 2004.

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 and fluctuations in interest rates and commodity prices, but prohibits the use of these instruments for speculative purposes.

SCE is exposed to credit loss in the event of nonperformance by counterparties. Counterparties are required to post collateral for certain transactions depending on the creditworthiness of each counterparty and the risk associated with the transaction. SCE does not expect the counterparties to fail to meet their obligations.

SCE records its derivative instruments on its 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 a designated hedge. For a designated hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of 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 a hedge is reflected in earnings immediately. Hedge accounting requires SCE to formally document, designate and assess the effectiveness of hedge transactions.

SCE enters into contracts for power and gas options, as well as swaps and futures, in order to mitigate its exposure to increases in natural gas and electricity pricing. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. Hedge accounting is not used for these transactions. Any fair value changes for recorded derivatives are offset through a regulatory mechanism; therefore, fair value changes do not affect earnings.

SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception under accounting rules is recorded on the balance sheet at fair value.

The carrying amounts and fair values of financial instruments are:

	December 31,			
	2004		2003	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Interest rate hedges	**$ 3**	**$ 3**	$ (1)	$ (1)
Commodity price assets	**14**	**14**	3	3
Commodity price liabilities	**(12)**	**(12)**	—	—
Other:				
Decommissioning trusts	**2,757**	**2,757**	2,530	2,530
DOE decommissioning and decontamination fees	**(13)**	**(13)**	(19)	(18)
QF power contracts	**(12)**	**(12)**	(32)	(32)
Long-term debt	**(5,225)**	**(5,551)**	(4,121)	(4,446)
Long-term debt due within one year	**(246)**	**(254)**	(371)	(377)
Preferred stock to be redeemed within one year	**(9)**	**(9)**	(9)	(9)
Preferred stock subject to mandatory redemption	**(139)**	**(140)**	(141)	(139)

Fair values are based on: brokers' quotes for interest rate hedges, long-term debt and preferred stock; financial models for commodity price derivatives and QF power contracts; quoted market prices for decommissioning trusts; and discounted future cash flows for United States Department of Energy (DOE) decommissioning and decontamination fees.

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

Note 4. Liabilities and Lines of Credit

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. SCE has debt covenants that require certain interest coverage, interest and preferred dividend coverage, and debt to total capitalization ratios to be met. At December 31, 2004, SCE was in compliance with these debt covenants.

Debt premium, discount and issuance expenses are deferred and amortized through interest expense 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,	**2004**	2003
First and refunding mortgage bonds:		
2007 – 2035 (4.65% to 8.00% and variable)	**$ 2,741**	$ 1,816
Rate reduction notes:		
2005 – 2007 (6.38% to 6.42%)	**739**	985
Pollution-control bonds:		
2006 – 2031 (2.0% to 7.2%)	**1,196**	1,216
Bonds repurchased	**—**	(354)
Debentures and notes:		
2006 – 2053 (5.06% to 7.625%)	**812**	758
Subordinated debentures:		
2044 (8.375%)	**—**	100
Long-term debt due within one year	**(246)**	(371)
Unamortized debt discount – net	**(17)**	(29)
Total	**$ 5,225**	$ 4,121

Note: Rates and terms as of December 31, 2004

Long-term debt maturities and sinking-fund requirements for the next five years are: 2005 – $246 million; 2006 – $927 million; 2007 – $1.4 billion; 2008 – $54 million; and 2009 – $219 million.

At December 31, 2004 and 2003 SCE had a credit line with a limit of $700 million. At December 31, 2004, SCE had $602 million in available credit under its credit line. The outstanding amount and weighted-average interest rate, respectively, for short-term debt was $88 million at 2.48% for December 31, 2004 and $200 million at 2.83% for December 31, 2003.

In January 2005, SCE issued $650 million of first and refunding mortgage bonds. The issuance included $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds were used to redeem $650 million of 8% first and refunding mortgage bonds due February 2007.

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. Dividend payments on preferred securities subject to mandatory redemption are included as interest expense effective July 1, 2003. The new standard did not allow for prior period restatements.

SCE has 12 million authorized shares of preferred stock subject to mandatory redemption. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock. Mandatorily redeemable preferred stock is subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid, if any, are charged to expense.

Preferred stock redemption requirements for the next five years are: 2005 – $9 million; 2006 – $9 million; 2007 – $74 million; 2008 – $56 million; and 2009 – none.

Cumulative preferred stock subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31, 2004 Shares Outstanding	December 31, 2004 Redemption Price	**2004**	2003
$100 par value:				
6.05% Series	673,800	$ 100.00	**$ 67**	$ 69
7.23	807,000	100.00	**81**	81
Preferred stock to be redeemed within one year			**(9)**	(9)
Total			**$ 139**	$ 141

The 6.05% Series preferred stock has mandatory sinking funds, requiring SCE to redeem at least 37,500 shares per year from 2003 through 2007, and 562,500 shares in 2008. SCE is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. In 2004, SCE redeemed 20,000 shares of 6.05% Series preferred stock. In 2003, SCE redeemed 56,200 shares of 6.05% Series preferred stock. At December 31, 2004, SCE had 1,200 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

The 7.23% Series preferred stock also has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE 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 the last three years. At December 31, 2004, SCE had 43,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

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

Note 5. Preferred Stock Not Subject to Mandatory Redemption

SCE's authorized shares are: $25 cumulative preferred – 24 million and preference – 50 million. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the last three years.

Cumulative preferred stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31, 2004 Shares Outstanding	December 31, 2004 Redemption Price	2004	2003
$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 income tax expense from continuing operations by location of taxing jurisdiction are:

In millions Year ended December 31,	2004	2003	2002
Current:			
Federal	**$ (88)**	$ 408	$ 990
State	**46**	174	273
	(42)	582	1,263
Deferred:			
Federal	**425**	(134)	(504)
State	**55**	(60)	(117)
	480	(194)	(621)
Total	**$ 438**	$ 388	$ 642

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

In millions December 31,	2004	2003
Deferred tax assets:		
Accrued charges	**$ 200**	$ 334
Investment tax credits	**64**	68
Property-related	**196**	243
Regulatory balancing accounts	**321**	204
Unrealized gains or losses	**392**	365
Decommissioning	**84**	106
Other	**245**	199
Total	**$ 1,502**	$ 1,519
Deferred tax liabilities:		
Property-related	**$ 2,915**	$ 2,762
Capitalized software costs	**164**	160
Regulatory balancing accounts	**710**	360
Unrealized gains and losses	**289**	262
Decommissioning	**31**	30
Other	**124**	108
Total	**$ 4,233**	$ 3,682
Accumulated deferred income taxes – net	**$ 2,731**	$ 2,163
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$ 2,865**	$ 2,726
Included in current assets	**134**	563

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

Year ended December 31,	2004	2003	2002
Federal statutory rate	**35.0%**	35.0%	35.0%
Tax audit adjustments	**(7.3)**	(2.8)	(1.9)
Resolution of FERC rate case	**—**	(5.9)	—
Property-related	**0.4**	0.1	0.4
Transition costs	**—**	—	(4.5)
State tax – net of federal deduction	**4.8**	6.0	5.4
Other	**(0.7)**	(1.9)	(0.4)
Effective tax rate	**32.2%**	30.5%	34.0%

The composite federal and state statutory income tax rate was 40.37% for 2004, and 40.551% for 2003 and 2002. The lower effective tax rate of 32.2% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years, property-related flow-through items, and other property-related adjustments. The lower effective tax rate of 30.5% realized in 2003 was primarily due to the resolution of a FERC rate case and recording the benefit of a favorable resolution of tax audit issues. The lower effective tax rate of 34.0% realized in 2002 was primarily due to reestablishing a tax-related regulatory asset due to implementation of the utility-retained generation decision and recording a benefit of a favorable settlement of tax 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. 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 $37 million in 2004, $33 million in 2003 and $30 million in 2002.

Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

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

At December 31, 2004 and December 31, 2003, 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 $38 million for the year ended December 31, 2005. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

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

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2004	2003
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 2,809**	$ 2,550
Service cost	**86**	79
Interest cost	**162**	162
Amendments	**22**	—
Actuarial loss	**106**	148
Benefits paid	**(152)**	(130)
Projected benefit obligation at end of year	**$ 3,033**	$ 2,809
Accumulated benefit obligation at end of year	**$ 2,627**	$ 2,424
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 2,779**	$ 2,281
Actual return on plan assets	**316**	594
Employer contributions	**38**	34
Benefits paid	**(152)**	(130)
Fair value of plan assets at end of year	**$ 2,981**	$ 2,779
Funded status	**$ (52)**	$ (30)
Unrecognized net loss	**105**	111
Unrecognized transition obligation	**1**	6
Unrecognized prior service cost	**91**	84
Recorded asset	**$ 145**	$ 171
Additional detail of amounts recognized in balance sheets:		
Intangible asset	**$ 2**	$ 3
Accumulated other comprehensive income	**(16)**	(16)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 77**	$ 78
Accumulated benefit obligation	**61**	60
Fair value of plan assets	—	—
Weighted-average assumptions at end of year:		
Discount rate	**5.5%**	6.0%
Rate of compensation increase	**5.0%**	5.0%

Expense components are:

In millions Year ended December 31,	**2004**	2003	2002
Service cost	**$ 86**	$ 79	$ 69
Interest cost	**162**	162	158
Expected return on plan assets	**(201)**	(187)	(224)
Special termination benefits	**—**	3	—
Net amortization and deferral	**22**	34	21
Expense under accounting standards	**69**	91	24
Regulatory adjustment – deferred	**(26)**	(44)	(18)
Total expense recognized	**$ 43**	$ 47	$ 6
Change in accumulated other comprehensive income	**$ —**	$ (7)	(9)
Weighted-average assumptions:			
Discount rate	**6.0%**	6.5%	7.0%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected return on plan assets	**7.5%**	8.5%	8.5%

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

In millions Year ended December 31,	
2005	$ 207
2006	220
2007	234
2008	248
2009	258
2010–2014	1,438
Total	$ 2,605

Asset allocations are:

	Target for 2005	December 31, **2004**	2003
United States equity	45%	**47%**	46%
Non-United States equity	25	**25**	26
Private equity	4	**2**	3
Fixed income	26	**26**	25

Postretirement Benefits Other Than Pensions

Employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits.

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

$116 million upon adoption. SCE's 2004 expense decreased by approximately $8 million as a result of the subsidy.

The expected contributions (all by the employer) to the postretirement benefits other than pensions trust are $76 million for the year ended December 31, 2005. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

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

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2004	2003
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,137**	$ 2,103
Service cost	**40**	42
Interest cost	**123**	122
Amendments	**28**	(622)
Actuarial loss (gain)	**(88)**	581
Benefits paid	**(94)**	(89)
Benefit obligation at end of year	**$ 2,146**	$ 2,137
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,389**	$ 1,072
Actual return on plan assets	**145**	291
Employer contributions	**25**	115
Benefits paid	**(94)**	(89)
Fair value of plan assets at end of year	**$ 1,465**	$ 1,389
Funded status	**$ (681)**	$ (748)
Unrecognized net loss	**841**	1,027
Unrecognized prior service cost	**(285)**	(342)
Recorded liability	**$ (125)**	$ (63)
Assumed health care cost trend rates:		
Rate assumed for following year	**10.0%**	12.0%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2010**	2010
Weighted-average assumptions at end of year:		
Discount rate	**5.75%**	6.25%

Expense components are:

In millions Year ended December 31,	**2004**	2003	2002
Service cost	**$ 40**	$ 42	$ 42
Interest cost	**123**	122	133
Expected return on plan assets	**(96)**	(89)	(93)
Special termination benefits	**—**	1	—
Amortization of unrecognized prior service costs	**(29)**	(20)	—
Amortization of unrecognized loss	**49**	52	10
Amortization of unrecognized transition obligation	**—**	9	27
Total expense	**$ 87**	$ 117	$ 119
Assumed health care cost trend rates:			
Current year	**12.0%**	9.75%	10.5%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2010**	2008	2008
Weighted-average assumptions:			
Discount rate	**6.25%**	6.4%	7.25%
Expected return on plan assets	**7.1%**	8.2%	8.2%

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2004 by $307 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, 2004 by $249 million and annual aggregate service and interest costs by $21 million.

The following benefit payments are expected to be paid:

In millions Year ended December 31,	
2005	$ 106
2006	104
2007	111
2008	111
2009	118
2010–2014	668
Total	$ 1,218

Asset allocations are:

	Target for 2005	December 31, **2004**	2003
United States equity	64%	**64%**	64%
Non-United States equity	16	**14**	13
Fixed income	20	**22**	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 Compensation

Under various plans, SCE may grant stock options at exercise prices equal to the market price at the grant date and other awards based on Edison International common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of up to five years, with expense accruing evenly over the vesting period. Edison International has approximately 14 million shares remaining for future issuance under equity compensation plans.

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

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

December 31,	**2004**	2003	2002
Expected years until exercise	**9 – 10**	10	7 – 10
Risk-free interest rate	**4.0% – 4.3%**	3.8% – 4.5%	4.7% – 6.1%
Expected dividend yield	**2.7% – 3.7%**	1.8%	1.8%
Expected volatility	**19% – 22%**	44% – 53%	18% – 54%

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

	Share Options	Weighted-Average Exercise Price	Weighted-Average Fair Value At Grant
Outstanding, Dec. 31, 2001	5,256,581	$ 23.70	
Granted	1,769,017	18.54	$ 7.86
Expired	(138,899)	24.88	
Forfeited	(73,651)	21.04	
Exercised	(2,250)	15.26	
Outstanding, Dec. 31, 2002	6,810,798	$ 22.37	
Granted	2,076,070	12.41	$ 7.34
Expired	(115,612)	22.98	
Forfeited	(59,473)	15.34	
Exercised	(156,697)	18.71	
Outstanding, Dec. 31, 2003	8,555,086	$ 20.06	
Granted	2,476,820	21.98	$ 6.61
Expired	(509)	16.23	
Forfeited	(79,536)	16.83	
Exercised	(1,589,948)	18.20	
Outstanding, Dec. 31, 2004	9,361,913	$ 20.91	

A summary of stock options outstanding at December 31, 2004 is as follows:

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Years of Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$ 8.90–$12.99	2,004,689	8	$ 12.19	489,038	$ 12.07
$13.00–$18.99	1,762,799	6	$ 18.23	896,330	$ 17.95
$19.00–$29.09	5,594,425	6	$ 24.87	3,161,343	$ 27.11
Total	9,361,913	6	$ 20.91	4,546,711	$ 23.69

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

Performance shares were awarded to executives in January 2002, January 2003 and January 2004 and vest at the end of December 2004, 2005 and 2006, respectively. The number of common shares paid out from the performance share awards depends on the performance of Edison International common stock relative to the stock performance of a specified group of companies. Performance share values are accrued ratably over the vesting period based on the value of the underlying Edison International common stock. The number of performance shares granted and their weighted-average grant-date fair value for 2004, 2003 and 2002 were 178,684 at $21.94, 293,497 at $12.33, and 218,248 at $15.20, respectively.

In November 2001, deferred stock units were issued in exchange for stock options granted in 2000. The deferred stock units vest at a rate of 25% per year over four years.

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

SCE's investment in each project as of December 31, 2004 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 48	$ 16	60%
Pacific Intertie	305	80	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	497	395	48
Mohave (coal)	347	262	56
Palo Verde (nuclear)	1,679	1,459	16
San Onofre (nuclear)	4,420	3,943	75
Total	$ 7,296	$ 6,155	

A portion of Mohave, San Onofre and Palo Verde is included in regulatory assets on the balance sheet. See Notes 1 and 2.

Note 9. Commitments

Leases

Operating lease expense was $17 million in 2004, $15 million in 2003 and $16 million in 2002. SCE's lease expense is primarily for vehicles; the leases have varying terms, provisions and expiration dates.

In accordance with an accounting standard, certain power contracts in which SCE takes virtually all of the power from specific power plants are classified as operating leases. Estimated remaining commitments for noncancelable leases (primarily for power purchases in 2005 and 2006) at December 31, 2004 are:

In millions Year ended December 31,	
2005	$ 48
2006	45
2007	9
2008	8
2009	5
Thereafter	9
Total	$ 124

Nuclear Decommissioning

As a result of an accounting standard adopted in 2003, SCE recorded the fair value of its liability for ARO, primarily related to the decommissioning of its nuclear power facilities. At that time, SCE adjusted its nuclear decommissioning obligation, capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The fair value of decommissioning SCE's nuclear power facilities is $2.2 billion as of December 31, 2004, 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 1.1% 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 is underway and will be completed in three phases: (1) decontamination and dismantling of all structures and some foundations; (2) spent fuel storage monitoring; and (3) fuel storage facility dismantling, removal of remaining foundations, and site restoration. Phase one is anticipated to continue through 2008. Phase two is expected to continue until 2026. Phase three will be conducted concurrently with the San Onofre Units 2 and 3 decommissioning projects. On February 3, 2004, SCE announced that it has discontinued plans to ship the San Onofre Unit 1 reactor pressure vessel to a disposal site until such time as appropriate arrangements are made for its permanent disposal. It will continue to be stored at its current location at San Onofre Unit 1, where it poses no risk to the public or the environment. This action results in placing the disposal of the reactor pressure vessel in Phase three of the San Onofre Unit 1 decommissioning project.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds, subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($154 million at December 31, 2004). Total expenditures for the decommissioning of San Onofre Unit 1 were $360 million through December 31, 2004.

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, 2004.

Decommissioning expense under the rate-making method was $125 million in 2004, $118 million in 2003 and $73 million in 2002. The ARO for decommissioning SCE's active nuclear facilities was $2.0 billion at December 31, 2004 and $1.9 billion at December 31, 2003.

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,	**2004**	2003
Municipal bonds	2005 – 2042		**$ 784**	$ 702
Stock	–		**1,403**	1,324
United States government issues	2005 – 2033		**485**	363
Corporate bonds	2005 – 2037		**41**	91
Short-term	2005		**44**	50
Total			**$ 2,757**	$2,530

Note: Maturity dates as of December 31, 2004.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (loss) were $91 million in 2004, $93 million in 2003 and $(25) million in 2002. Proceeds from sales of securities (which are reinvested) were $2.5 billion in 2004, $2.2 billion in 2003 and $3.8 billion in 2002. Net unrealized holding gains were $796 million and $677 million at December 31, 2004 and 2003, respectively. Approximately 91% of the cumulative trust fund contributions were tax-deductible.

Other Commitments

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

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

Certain commitments for the years 2005 through 2009 are estimated below:

In millions	2005	2006	2007	2008	2009
Fuel supply	$ 173	$ 58	$ 65	$ 59	$ 36
Purchased power	898	725	648	421	394

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the transmission line is operable. The contract requires minimum payments of $69 million through 2016 (approximately $6 million per year).

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. The generating station has not operated since early 2001, and SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

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.

Environmental Remediation

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

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

SCE's recorded estimated minimum liability to remediate its 24 identified sites is $82 million. 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 $123 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also had 30 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $27 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 $55 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 2004 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

Edison International has reached a tentative settlement with the Internal Revenue Service (IRS) on tax issues and pending affirmative claims relating to its 1991 to 1993 tax years currently under appeal. This settlement, which should be finalized in 2005, is expected to result in a net earnings benefit for SCE of approximately $70 million.

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

The IRS Revenue Agent Report for the 1997 to 1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

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

Investigations Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability.

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

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties to SCE under the PBR provisions for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003.

SCE has been conducting an internal investigation and keeping the CPUC informed of its progress. On June 25, 2004, SCE submitted to the CPUC a PBR customer satisfaction investigation report, which concluded that employees in the design organization of the transmission and distribution business unit deliberately altered customer contact information in order to affect the results of customer satisfaction surveys. At least 36 design organization personnel engaged in deliberate misconduct including alteration of customer information before the data were transmitted to the independent survey company. Because of the apparent scope of the misconduct, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forego an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997–2003). In addition, during its investigation, SCE determined that it could not confirm the integrity of the method used for obtaining customer satisfaction survey data for meter reading. Thus, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading. As a result of these findings, SCE accrued a $9 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by severing the employment of several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 general rate case.

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

Employee Injury and Illness Reporting

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

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. Under the PBR mechanism, rewards and/or penalties for the years 1997 through 2003 were based upon a total incident rate, which included two equally weighted measures: Occupational Safety and Health Administration (OSHA) recordable incidents and first aid incidents. The major issue disclosed in the investigative findings to the CPUC was that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents. SCE's investigation also found reporting inaccuracies for OSHA recordable incidents, but the impact of these inaccuracies did not have a material effect on the PBR mechanism.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism for any year before 2005, and it return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001–2003 time frames.

SCE is taking other remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance. Additional actions, including disciplinary action against specific employees identified as having committed wrongdoing, may result once the investigation is completed. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004. As with the customer satisfaction matter, the CPUC has not yet opened a formal investigation into this matter. However, SCE anticipates that the CPUC will be submitting data requests and seeking additional information in the near future.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE is conducting an investigation into the third PBR metric, system reliability. Since the inception of PBR payments in 1997, SCE has received $8 million in rewards and has applied for an additional $5 million reward based on frequency of outage data for 2001. For 2002, SCE's data indicates that it earned no reward and incurred no penalty. Based on the application of the PBR mechanism, as adopted, SCE's data would result in penalties of $5 million and $1 million, for 2003 and 2004, respectively. These penalties have not yet been assessed. As a result of SCE's data and calculations, SCE has accrued a $6 million charge in the caption "Other nonoperating deductions" on the income statement in 2004.

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

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss. The D.C. District Court denied these motions for dismissal, except for Salt River Project Agricultural Improvement and Power District's motion for its separate dismissal from the lawsuit.

Certain issues related to this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the United States Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE and Peabody filed motions to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. On April 13, 2004, the D.C. District Court denied SCE's and Peabody's April 2003 motions to dismiss or, in the alternative, for summary judgment. The D.C. District Court subsequently issued a scheduling order that imposed a December 31, 2004 discovery cut-off. Pursuant to a joint request of the parties, the D.C. District Court granted a 120-day stay of the action to allow the parties to attempt to resolve, through facilitated negotiations, all issues associated with Mohave. Negotiations are ongoing and the stay has been continued until further order of the court.

The United States Court of Appeals for the D.C. Circuit, acting on a suggestion on remand filed by the Navajo Nation, held in an October 24, 2003 decision that the Supreme Court's March 4, 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 D.C. Circuit Court decision. Both petitions were denied on March 9, 2004. On March 16, 2004, the D.C. Circuit Court issued an order remanding the case against the Government to the Court of Federal Claims, which conducted a status conference on May 18, 2004. As a result of the status conference discussion, the Navajo Nation and the Government are in the process of briefing the remaining issues following remand. Peabody's motion to intervene as a party in the remanded Court of Federal Claims case was denied.

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 $10.8 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The 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. All licensed operating plants including San Onofre and Palo Verde are grandfathered under the applicable law.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $44 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

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

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation. 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 was completed in late 2004. Movement of Unit 1 spent fuel from the Unit 2 spent fuel pool to the independent spent fuel pool storage installation is scheduled to be completed by summer 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 late 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 March 12, 2004, SCE acquired Mountainview Power Company LLC, which owns a power plant under construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project, which is expected to be completed in early 2006.

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 2002 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.

Quarterly Financial Data (Unaudited)

	2004					2003				
In millions	**Total**	**Fourth**	**Third**	**Second**	**First**	**Total**	**Fourth**	**Third**	**Second**	**First**
Operating revenue	**$8,448**	**$1,920**	**$2,655**	**$2,176**	**$1,696**	$8,854	$1,859	$2,794	$2,386	$1,815
Operating income	**2,013**	**499**	**682**	**587**	**245**	1,578	293	609	416	260
Net income	**921**	**317**	**260**	**243**	**101**	932	223	375	229	105
Net income available for common stock	**915**	**315**	**259**	**242**	**100**	922	222	374	225	101
Common dividends declared	**750**	**155**	**150**	**145**	**300**	945	945	—	—	—

Operating income was restated for prior quarters due to a reclassification of performance share expense from nonoperating to operating expenses

Totals may not add precisely due to rounding.

Dollars in millions	**2004**	2003	2002	2001	2000
Income statement data:					
Operating revenue	**$ 8,448**	$ 8,854	$ 8,706	$ 8,126	$ 7,870
Operating expenses	**6,435**	7,276	6,588	3,509	10,529
Purchased-power expenses	**2,332**	2,786	2,016	3,770	4,687
Income tax (benefit)	**438**	388	642	1,658	(1,022)
Provisions for regulatory adjustment clauses – net	**(201)**	1,138	1,502	(3,028)	2,301
Interest expense – net of amounts capitalized	**409**	457	584	785	572
Net income (loss) from continuing operations	**921**	882	1,247	2,408	(2,028)
Net income (loss)	**921**	932	1,247	2,408	(2,028)
Net income (loss) available for common stock	**915**	922	1,228	2,386	(2,050)
Ratio of earnings to fixed charges	**4.40**	3.81	4.21	6.15	*

*less than 1.00

Balance sheet data:					
Assets	**$ 23,290**	$ 21,771	$ 36,058	$ 22,453	$ 15,966
Gross utility plant	**17,981**	16,991	16,232	15,982	15,653
Accumulated provision for depreciation and decommissioning	**4,506**	4,386	4,057	7,969	7,834
Short-term debt	**88**	200	—	2,127	1,451
Common shareholder's equity	**4,521**	4,355	4,384	3,146	780
Preferred stock:					
Not subject to mandatory redemption	**129**	129	129	129	129
Subject to mandatory redemption	**139**	141	147	151	256
Long-term debt	**5,225**	4,121	4,525	4,739	5,631
Capital structure:					
Common shareholder's equity	**45.1%**	49.8%	47.7%	38.5%	11.5%
Preferred stock:					
Not subject to mandatory redemption	**1.3%**	1.5%	1.4%	1.6%	1.9%
Subject to mandatory redemption	**1.4%**	1.6%	1.6%	1.9%	3.8%
Long-term debt	**52.2%**	47.1%	49.3%	58.0%	82.8%

Operating data:					
Peak demand in megawatts (MW)	**20,762**	20,136	18,821	17,890	19,757
Generation capacity at peak (MW)	**10,207**	9,861	9,767	9,802	9,886
Kilowatt-hour deliveries (in millions)	**97,273**	92,763	79,693	78,524	84,430
Total energy requirement (kWh) (in millions)	**78,738**	77,158	71,663	83,495	82,503
Energy mix:					
Thermal	**33.7%**	37.9%	40.2%	32.5%	36.0%
Hydro	**4.5%**	5.2%	5.0%	3.6%	5.4%
Purchased power and other sources	**61.8%**	56.9%	54.8%	63.9%	58.6%
Customers (in millions)	**4.67**	4.60	4.53	4.47	4.42
Full-time employees	**13,454**	12,698	12,113	11,663	12,593

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 nonutility subsidiary of Edison
International, an investor in
infrastructure and energy assets)
A director from 1990-1990;
2003 to present

France A. Córdova [2,4]
Chancellor,
University of California, Riverside
Riverside, California
A director since 2004

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

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

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

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

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

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

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

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

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

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

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.

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

Harry B. Hutchison
Vice President,
Customer Service Operations

Walter J. Johnston
Vice President,
Power Delivery

Brian Katz
Vice President,
Nuclear Oversight and
Regulatory Affairs

James A. Kelly
Vice President,
Engineering and Technical Services

Russ W. Krieger
Vice President,
Power Production

Thomas M. Noonan
Vice President,
Chief Financial Officer,
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

Barbara A. Reeves
Vice President,
Shared Services

Anthony L. Smith
Vice President,
Tax

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

Raymond W. Waldo
Vice President,
Nuclear Generation

Beverly P. Ryder
Corporate Secretary

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Shareholder Information

Annual Meeting

The annual meeting of shareholders will be held on Thursday, May 19, 2005, at 10:00 a.m., Pacific Time, at the Pacific Palms Conference Resort; One Industry Hills Parkway, City of Industry, California 91744.

Corporate Governance Practices

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

Stock Listing and Trading Information

Preferred Stock

SCE's 4.08%, 4.24%, 4.32% and 4.78% Series of $25 par value cumulative preferred stock are listed on the American Stock Exchange under the ticker symbol SCE. Previous day's closing prices, when stock was traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05% and 7.23%(1) Series of the $100 par value 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 stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

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

Inquiries may also be directed to:

Mail

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

Fax

(651) 450-4033

Email

stocktransfer@wellsfargo.com

Web Address

www.edisoninvestor.com

Online account information:

www.shareowneronline.com

(1) The 7.23% Series will be redeemed on April 26, 2005.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL® Company

2244 Walnut Grove Avenue
Rosemead, California 91770
www.sce.com