SOUTHERN CALIFORNIA
EDISON®

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2001 Annual Report

Southern California Edison Company

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

SCE, a 116-year-old electric utility, serves a 50,000-square-mile area of central, coastal and southern California.

Contents

Selected Financial and Operating Data: 1997 – 2001

Southern California Edison Company

Dollars in millions	**2001**	2000	1999	1998	1997
Income statement data:					
Operating revenue	**$ 8,126**	$ 7,870	$ 7,548	$ 7,500	$ 7,953
Operating expenses	**3,509**	10,529	6,242	6,136	6,311
Fuel and purchased power expenses	**3,982**	4,882	3,405	3,586	3,735
Income tax (benefit)	**1,658**	(1,022)	438	442	520
Provisions for regulatory adjustment clauses – net	**(3,028)**	2,301	(763)	(473)	(411)
Interest expense – net of amounts capitalized	**785**	572	483	485	444
Net income (loss)	**2,408**	(2,028)	509	515	606
Net income (loss) available for common stock	**2,386**	(2,050)	484	490	576
Ratio of earnings to fixed charges	**6.15**	(4.28)	2.94	2.95	3.49
Balance sheet data:					
Assets	**$ 22,453**	$ 15,966	$ 17,657	$ 16,947	$ 18,059
Gross utility plant	**15,982**	15,653	14,852	14,150	21,483
Accumulated provision for depreciation and decommissioning	**7,969**	7,834	7,520	6,896	10,544
Short-term debt	**2,127**	1,451	796	470	322
Common shareholder’s equity	**3,146**	780	3,133	3,335	3,958
Preferred stock:					
Not subject to mandatory redemption	**129**	129	129	129	184
Subject to mandatory redemption	**151**	256	256	256	275
Long-term debt	**4,739**	5,631	5,137	5,447	6,145
Capital structure:					
Common shareholder’s equity	**38.5%**	11.5%	36.2%	36.4%	37.5%
Preferred stock:					
Not subject to mandatory redemption	**1.6%**	1.9%	1.5%	1.4%	1.7%
Subject to mandatory redemption	**1.9%**	3.8%	2.9%	2.8%	2.6%
Long-term debt	**58.0%**	82.8%	59.4%	59.4%	58.2%
Operating data:					
Peak demand in megawatts (MW)	**17,890**	19,757	19,122	19,935	19,118
Generation capacity at peak (MW)	**9,802**	9,886	10,431	10,546	21,511
Kilowatt-hour deliveries (in millions)	**78,524**	84,430	78,602	76,595	77,234
Total energy requirement (kWh) (in millions)	**83,496**	82,503	78,752	80,289	86,849
Energy mix:					
Thermal	**32.5%**	36.0%	35.5%	38.8%	44.6%
Hydro	**3.6%**	5.4%	5.6%	7.4%	6.5%
Purchased power and other sources	**63.9%**	58.6%	58.9%	53.8%	48.9%
Customers (in millions)	**4.47**	4.42	4.36	4.27	4.25
Full-time employees	**11,663**	12,593	13,040	13,177	12,642

Management's Discussion and Analysis of Results of Operations and Financial Condition

The following discussion contains forward-looking statements. These statements are based on Southern California Edison's (SCE) current expectations about future events, based on knowledge of present facts and assumptions about future developments. These forward-looking statements are subject to risks and uncertainties that could cause actual future activities and results of operations to be materially different from those set forth in this discussion. Important factors that could cause actual results to differ include risks discussed in the Market Risk Exposures and Forward-Looking Statements sections.

Until early 2002, SCE faced a crisis resulting from deregulation of the generation side of the electric utility industry through legislation enacted by the California Legislature and decisions issued by the California Public Utilities Commission (CPUC). Under the legislation and CPUC decisions, prices for wholesale purchases of electricity from power suppliers are set by markets while the retail prices paid by utility customers for electricity delivered to them remain frozen at June 1996 levels except for the 10% residential rate reduction starting in 1998 and the 4¢-per-kWh surcharge effective in 2001. See further discussion of the CPUC rate increases in Rate Stabilization Proceedings. Beginning in May 2000, SCE's costs to obtain power (at wholesale electricity prices) for resale to its customers substantially exceeded revenue from frozen rates. The shortfall was accumulated in the transition revenue account (TRA), a CPUC-authorized regulatory asset. As a result of a March 27, 2001, CPUC decision, the TRA balance was transferred retroactively to the transition cost balancing account (TCBA). The TCBA was a regulatory balancing account that tracked the recovery of generation-related transition costs, including stranded investments. SCE has borrowed significant amounts of money to finance its electricity purchases. Uncertainty regarding SCE's ability to recover funds spent to purchase power created a severe liquidity crisis at SCE. However, based on the settlement agreement with the CPUC (discussed below) permitting full recovery of past power procurement costs, SCE was able to arrange new financing and together with cash on hand, was able to repay its undisputed past-due obligations in March 2002.

In October 2001, a federal district court in California entered a stipulated judgment approving an agreement between the CPUC and SCE to settle a lawsuit. On January 23, 2002, the CPUC adopted a resolution approving the establishment of the procurement-related obligations account (PROACT). See discussion below. SCE believes that the settlement agreement will enable SCE to recover its previously undercollected power procurement costs. In compliance with the terms of the settlement agreement and the CPUC resolution, in the fourth quarter of 2001, SCE established a $3.6 billion regulatory asset for these previously incurred procurement costs, called the PROACT. A corresponding credit to earnings was recorded, in connection with this regulatory asset, in the amount of $3.6 billion ($2.1 billion after tax).

On September 1, 2001, SCE began applying to the PROACT the difference between SCE's revenue from retail electric rates and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The settlement also calls for the end of the TCBA mechanism as of August 31, 2001, and continuation of the rate freeze until the earlier of December 31, 2003, or the date that SCE recovers the PROACT balance. If SCE has not recovered the entire PROACT balance by the end of 2003, the remaining balance will be amortized in retail rates for up to an additional two years. For further details on the settlement with the CPUC and the CPUC resolution, see CPUC Litigation Settlement Agreement and PROACT Regulatory Asset discussions.

Accounting principles generally accepted in the United States permit SCE to defer costs and record regulatory assets if those costs are determined to be probable of recovery in future rates. SCE assessed the probability of recovery of the undercollected costs that were previously recorded in the TCBA in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes that are discussed in more detail in Rate Stabilization Proceedings. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. As a result, SCE's financial results for the year ended December 31, 2000, included an after-tax charge of approximately $2.5 billion ($4.2 billion pre-tax), reflecting a write-off of the TCBA and net regulatory assets to be recovered through the TCBA mechanism, as of December 31, 2000. Transition costs in excess of transition revenue were also incurred during 2001, resulting in additional net charges against earnings of $328 million ($552 million pre-tax) through August 31, 2001 (the effective date of the PROACT mechanism).

The following pages include a discussion of the history of the TRA and TCBA and related circumstances, the significantly negative effect on the financial condition of SCE of undercollections recorded in the TRA and TCBA, the current status of the undercollections, the impact of the CPUC's March 27, 2001, decisions and related matters, and the implementation of the CPUC settlement agreement and the PROACT mechanism, and SCE's March 2002 financing.

Results of Operations

Earnings

In 2001, SCE earned $2.4 billion, compared with a loss of $2.1 billion in 2000 and earnings of $484 million in 1999. SCE's 2001 earnings included a $2.1 billion (after tax) benefit resulting from the reestablishment of procurement-related regulatory assets and liabilities as a result of the PROACT resolution and recovery of $178 million (after tax) of previously written off generation-related regulatory assets, partially offset by $328 million (after tax) of net undercollected transition costs incurred between January and August 2001. SCE's loss in 2000 included a $2.5 billion (after tax) write-off of regulatory assets and liabilities as of December 31, 2000. SCE's 1999 earnings included a $15 million one-time tax benefit due to an Internal Revenue Service ruling. Excluding the $2.0 billion net benefit in 2001, the $2.5 billion (after tax) write-off in 2000 and the $15 million benefit in 1999, SCE's earnings were $408 million in 2001, $471 million in 2000 and $469 million in 1999. The $63 million decrease in 2001 was primarily due to the February 2001 fire and resulting outage at San Onofre Nuclear Generation Station Unit 3 and lower kilowatt-hour sales. In 2000, superior operating performance at San Onofre and higher kilowatt-hour sales were almost completely offset by adjustments to reflect potential regulatory refunds and lower gains from sales of equity investments.

Accounting principles generally accepted in the United States require SCE at each financial statement date to assess the probability of recovering its regulatory assets through a regulatory process. Based on the rules arising from the CPUC's March 27, 2001, rate stabilization decision, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections were reclassified, and the TCBA balance was recalculated to be a $2.9 billion undercollection (see further discussion of the CPUC rate increase in the Rate Stabilization Proceeding section and the components of the TCBA undercollection in the Status of Transition and Power-Procurement Cost Recovery section of Regulatory Environment). As a result, SCE was unable to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other net regulatory assets that were to be recovered through the TCBA mechanism by the end of the rate freeze, were probable of recovery through the rate-making process as of December 31, 2000. As a result, SCE's December 31, 2000, income statement included a $4.0 billion charge to provisions for regulatory adjustment clauses and a $1.5 billion net reduction in income tax expense, to reflect the $2.5 billion (after tax) write-off.

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

Operating Revenue

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an energy service provider (thus becoming direct access customers) or continue to have SCE purchase power on their behalf. Most direct access customers continued to be billed by SCE, but were given a credit for the generation purchased from the energy service provider. Operating revenue is reported net of this credit. On September 20, 2001, the CPUC suspended the ability of retail customers to select alternative providers of electricity until the California Department of Water Resources (CDWR) stops buying power for retail customers, pending further review by the CPUC. On March 21, 2002, the

CPUC issued a final decision affirming September 20, 2001, as the date when direct access was suspended in the state.

During 2000, as a result of the power shortage in California, SCE's customers on interruptible rate programs (which provide for lower generation rates with a provision that service can be interrupted if needed, with penalties for noncompliance) were asked to curtail their electricity usage at various times. As a result of noncompliance with SCE's requests, those customers were assessed significant penalties. On January 26, 2001, the CPUC waived the penalties assessed to noncompliant customers after October 1, 2000, until the interruptible programs can be reevaluated.

Operating revenue increased in 2001 (as shown in the table below), primarily due to the effects of the reduced credits given to direct access customers in 2001 and the 4¢-per-kWh (1¢ in January and 3¢ in June) surcharge effective in 2001. The increases were partially offset by: a decrease in retail sales volume primarily attributable to conservation efforts; a decrease in revenue related to penalties customers incurred for not complying with their interruptible contracts; a decrease in revenue related to operation and maintenance services; and a decrease in revenue related to electric power provided to SCE customers by the CDWR or Independent System Operator (ISO). Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR or through the ISO on behalf of SCE's customers (beginning January 17, 2001) are being remitted to the CDWR and are not recognized as revenue by SCE. In 2001, this amount was $2.0 billion. See CDWR Power Purchases discussion.

Operating revenue increased in 2000 (as shown in the table below), primarily due to: warmer weather in the second and third quarters of 2000 as compared to the same periods in 1999; increased resale sales; and an increase in revenue related to penalties customers incurred for not complying with their interruptible contracts.

The changes in operating revenue resulted from:

In millions Year ended December 31,	**2001**	2000	1999
Operating revenue –			
Rate changes (including refunds)	**$ 422**	$ 120	$ (75)
Direct access credit	**566**	(434)	(213)
Interruptible noncompliance penalty	**(117)**	102	6
Sales volume changes	**(544)**	520	195
Other	**(71)**	14	136
Total	**$ 256**	$ 322	$ 49

More than 94% of operating revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Due to warmer weather during the summer months, operating revenue during the third quarter of each year is significantly higher than other quarters.

Operating Expenses

Fuel expense increased in 2001 and decreased in 2000. The increase in 2001 and the decrease in 2000 were both due to fuel-related refunds resulting from a settlement with another utility that SCE recorded in the second and third quarters of 2000.

Purchased-power expense decreased in 2001 and increased in 2000. The 2001 decrease resulted from the absence of California Power Exchange (PX)/ISO purchased-power expense after mid-January 2001, partially offset by increased expenses related to qualifying facilities (QFs), bilateral contracts and interutility contracts. See Purchased Power table in Note 1 to the Consolidated Financial Statements and discussion in CDWR Power Purchases. PX/ISO purchased-power expense increased significantly between May 2000 and mid-

January 2001, due to a number of factors, including increased demand for electricity in California, dramatic price increases for natural gas (a key input of electricity production), and problems in the structure and conduct of the PX and ISO markets. In December 2000, the FERC eliminated the requirement that SCE buy and sell all power through the PX and ISO. Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions in the day-ahead and day-of markets as a result of the downgrade in its credit rating, the PX suspended SCE's market trading privileges effective mid-January 2001.

Prior to April 1998, federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices even though energy and capacity prices under many of these contracts are generally higher than other sources. These contracts expire on various dates through 2025. See further discussion regarding new QF agreements in Litigation. Purchased-power expense related to QFs increased due to the short-run avoided cost factor (which is based on the price of natural gas) of the QF contracts causing a significant increase in the payments to QFs. In early 2001, structural problems in the market caused abnormally high gas prices. The increase related to bilateral contracts was the result of SCE not having these contracts in 2000. The increase related to interutility contracts was volume-driven.

SCE has contracts with certain QFs in which Edison Mission Energy (a wholly owned subsidiary of Edison International) has 49% – 50% interests. The terms and pricing of these contracts are approved by the CPUC. SCE's power purchases from these facilities were $983 million in 2001, $716 million in 2000 and $513 million in 1999.

Provisions for regulatory adjustment clauses decreased for 2001 and increased for 2000. The 2001 decrease resulted from SCE recording the $3.6 billion PROACT regulatory asset in fourth quarter 2001. The increase in 2000 was mainly due to SCE's write-off as of December 31, 2000, of $4.2 billion in regulatory assets and liabilities as a result of the California energy crisis. Adjustments to reflect potential regulatory refunds related to the outcome of the CPUC's reevaluation of the operation of the interruptible rate programs also contributed to the increase in 2000.

Other operation and maintenance expense decreased in 2000. The decrease was primarily due to a $120 million decrease in mandated transmission service (known as reliability must-run services) expense and a $19 million decrease in operating expenses at San Onofre. The decrease at San Onofre in 2000 was primarily due to scheduled refueling outages for both units in the first half of 1999. San Onofre had only one refueling outage in 2000.

Depreciation, decommissioning and amortization expense decreased in 2001, mainly due to SCE's nuclear investment amortization expense ceasing since the unamortized nuclear investment regulatory asset was included in the December 31, 2000, write-off.

Net gain on sale of utility plant in 2000 resulted from the sale of additional property related to four of the generating stations SCE sold in 1998. The gains were returned to the ratepayers through the TCBA mechanism.

Other Income and Deductions

Interest and dividend income increased in both 2001 and 2000. The increase in 2001 was mainly due to an overall higher cash balance, as SCE conserved cash due to its liquidity crisis. The increase in 2000 was mostly due to increases in interest earned on higher balancing account undercollections.

Other nonoperating income decreased in both 2001 and 2000. The decrease in 2001 primarily reflects the gains on sales of marketable securities in 2000. The decrease in 2000 was primarily due to larger gains on sales of marketable securities in 1999.

Interest expense – net of amounts capitalized increased in both 2001 and 2000. The increase in 2001 reflects additional long-term debt and higher short-term debt balances. The increase in 2000 was mostly due to higher overall short-term debt balances necessary to meet general cash requirements (especially PX and ISO payments) and higher interest expense related to balancing account overcollections.

Other nonoperating deductions decreased in 2001 primarily due to lower accruals for regulatory matters in 2001.

Income Taxes

Income taxes increased in 2001 and decreased in 2000. The increase in 2001 reflects $1.5 billion in income tax expense related to the PROACT regulatory asset establishment in fourth quarter 2001. The decrease in 2000 was primarily due to the $1.5 billion income tax benefit related to the write-off as of December 31, 2000, of regulatory assets and liabilities in the amount of $2.5 billion (after tax). Absent the impact of the PROACT regulatory asset in 2001 and the write-off in 2000, SCE's income tax expense increased in both 2001 and 2000 due to higher pre-tax income in both years.

Financial Condition

SCE's liquidity is affected primarily by regulation affecting its ability to recover the cost of power purchases, debt maturities, access to capital markets, credit ratings, dividend payments and capital expenditures. Capital resources include cash from operations and external financings.

Liquidity Issues

Sustained higher wholesale energy prices that began in May 2000 persisted through June 2001. This resulted in undercollections in the TRA and TCBA. Undercollections, coupled with SCE's anticipated near-term capital requirements (detailed in Projected Commitments) and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, materially and adversely affected SCE's liquidity throughout 2001. As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, beginning in January 2001, SCE suspended payments owed to the ISO, the PX and QFs, deferred payments of certain obligations for principal and interest on outstanding debt and did not declare dividends on any of its cumulative preferred stock. As applicable, unpaid obligations continued to accrue interest. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. However, since June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. All interest in arrears must be paid at the end of the deferral period. As long as accumulated dividends on SCE's preferred stock remain unpaid, SCE could not pay dividends on its common stock. Common stock dividends are additionally restricted as detailed in the CPUC Litigation Settlement discussion.

Based on the rights to cost recovery and revenue established by the settlement agreement with the CPUC and CPUC implementing orders, including the PROACT resolution, SCE repaid its undisputed past-due obligations on March 1, 2002, with lump-sum payments to creditors from the proceeds of $1.6 billion in senior secured credit facilities, the remarketing of $196 million in pollution-control bonds which were repurchased in late 2000, and existing cash on hand. The $1.6 billion senior secured credit facilities consist of a $300 million, two-year revolving credit loan, a $600 million, one-year loan and a $700 million, three-year loan.

The proceeds from the senior secured credit facilities and pollution-control bond remarketing were used, along with SCE's available cash, to repay $3.2 billion in past-due obligations and $1.65 billion in near-term debt maturities. The past-due obligations consisted of: (1) $875 million to the PX; (2) $99 million to the ISO; (3) $1.1 billion to QFs; (4) $193 million in PX energy credits for energy service providers; (5) $531 million of matured commercial paper; (6) $400 million of principal on its 5-7/8% and 6-1/2% senior unsecured notes which were issued prior to the energy crisis; and (7) $23 million in preferred dividends in arrears. The near-term debt maturities consisted of credit facilities whose maturity dates were extended several times and were scheduled to mature in March and May 2002. In addition, SCE entered into an agreement with the CDWR to pay for prior deliveries of energy in installments of $100 million on April 1, 2002, $150 million on June 3, 2002, and the balance on July 1, 2002. After making the above-described payments, SCE has no material undisputed obligations that are past due or in default.

SCE expects to meet its continuing obligations from remaining cash on hand and future operating cash flows.

For additional discussion on the impact of California's energy crisis on SCE's liquidity, see Cash Flows from Financing Activities. For a discussion on the settlement agreement with the CPUC and the PROACT resolution to resolve SCE's crisis, see CPUC Litigation Settlement Agreement and PROACT Regulatory Asset sections.

Cash Flows from Operating Activities

Net cash provided by operating activities was $3.3 billion in 2001, $829 million in 2000 and $1.5 billion in 1999. The increase in 2001 was primarily due to SCE suspending payments for purchased power and other obligations beginning in January 2001. Cash provided by operating activities also reflects the CPUC-approved surcharges (1¢ per kWh in January and 3¢ per kWh in June) that were billed in 2001. The decrease in 2000 was the result of extremely high prices SCE paid for energy and ancillary services procured through the PX and ISO.

Cash Flows from Financing Activities

At December 31, 2001, SCE had drawn on its entire credit lines of $1.65 billion. These unsecured lines of credit have various expiration dates and, when available, could be drawn down at negotiated or bank index rates. On March 1, 2002, SCE's credit lines ($1.65 billion) were repaid using proceeds from the March 1, 2002, financing. See additional discussion in Liquidity Issues.

Short-term debt is used to finance balancing account undercollections, fuel inventories and general cash requirements, including purchased-power payments. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors. Because of the $2.5 billion charge to earnings as of December 31, 2000, SCE does not currently meet the interest coverage ratio that is required for SCE to issue additional preferred stock.

As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, during December 2000 and early 2001, SCE had to repurchase $550 million of pollution-control bonds that could not be remarketed in accordance with their terms. SCE remarketed $196 million of these bonds in March 2002 (see additional discussion in Liquidity Issues). The remaining amount of these bonds may be remarketed in the future. In addition, SCE remains unable to sell its commercial paper and other short-term financial instruments.

Although Fitch IBCA, Standard & Poor's and Moody's Investors Service raised their credit ratings significantly for SCE in March 2002, the new ratings are still below investment grade. The new ratings reflect the ongoing financial recovery of SCE that began in October 2001 with SCE's settlement agreement with the CPUC and has continued with the CPUC's January 2002 PROACT resolution and the repayment of SCE's past-due obligations. SCE lost its investment-grade ratings in January 2001.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, thereby limiting the dividends it may pay Edison International.

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 non-bypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these non-bypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities beginning in 2002 and ending in 2007, with interest rates ranging from 6.22% to 6.42%. The notes are secured by the transition property and are not secured 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. Due to its credit rating downgrade in late 2000, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant and funding of nuclear decommissioning trusts. Decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $25 million per year. In 1995, the CPUC determined the restrictions related to the investments of these trusts. They are: not more than 50% of the fair market value of the qualified trusts may be invested in equity securities; not more than 20% of the fair market value of the trusts may be invested in international equity securities; up to 100% of the fair market values of the trusts may be invested in investment grade fixed-income securities including, but not limited to, government, agency, municipal, corporate, mortgage-backed, asset-backed, non-dollar, and cash equivalent securities; and derivatives of all descriptions are prohibited. 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.

Projected Commitments

SCE's projected construction expenditures for 2002 are $921 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 2002 – $1.1 billion; 2003 – $1.4 billion; 2004 – $371 million; 2005 – $246 million; and 2006 – $446 million.

Fuel supply contract payments for the next five years are: 2002 – $168 million; 2003 – $108 million; 2004 – $103 million; 2005 – $106 million; and 2006 – $109 million.

Purchased-power capacity payments for the next five years are: 2002 – $629 million; 2003 – $629 million; 2004 – $626 million; 2005 – $624 million; and 2006 – $572 million.

Preferred stock redemption requirements for the next five years are: 2002 – $105 million; 2003 – $9 million; 2004 – $9 million; 2005 – $9 million; and 2006 – $9 million.

Market Risk Exposures

SCE's primary market risk exposures include commodity price risk and interest rate risk that could adversely affect results of operations or financial position. Commodity price risk arises from fluctuations in the market price of an energy commodity, such as electricity, natural gas, or coal. Interest rate risk arises from fluctuations in interest rates. Additionally, natural gas is a key input for the prices specified in approximately half of SCE's QF (including non-gas QF) contracts. Virtually all of SCE's exposure to changes in the spot market price for natural gas through 2003 is hedged through financial derivatives or fixed-price contracts. SCE's risk management policy allows the use of derivative financial instruments to manage its financial exposures, but prohibits the use of these instruments for speculative or trading purposes.

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. As a result of California's energy crisis, SCE has been exposed to significantly higher interest rates, which intensified its liquidity crisis during 2001 (further discussed in the Liquidity Issues section of Financial Condition).

At December 31, 2001, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to its carrying value. SCE did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2001, a 10% increase in market interest rates would have resulted in a $128 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 $141 million increase in the fair market value of SCE's long-term debt.

Since April 1998, the price SCE paid to acquire power on behalf of customers was allowed to float, in accordance with the 1996 electric utility restructuring law. Until May 2000, retail rates were sufficient to cover the cost of power and other SCE costs. However, between May 2000 and June 2001, market power prices escalated, creating a substantial gap between costs and retail rates. In response to the dramatically higher prices, the ISO and the FERC have placed certain caps on the price of power (see further discussion in Wholesale Electricity Markets).

Under the terms of the CPUC settlement agreement, SCE purchased $209 million in hedging instruments (gas call options) in October and November 2001 to hedge a majority of its natural gas price exposure associated with QF contracts for 2002 and 2003. Although these gas call options are reflected in the income statement, any fair value changes of the gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings. At December 31, 2001, a 10% increase in market gas prices would have resulted in a $32 million increase in the fair market value of SCE's gas call options. A 10% decrease in market gas prices would have resulted in a $27 million decrease in the fair market value of the gas call options.

In accordance with an accounting standard for derivatives, on January 1, 2001, SCE recorded its block-forward contracts at fair value on the balance sheet. Because SCE suspended payments for purchased power on January 16, 2001, the PX sought to liquidate SCE's remaining block-forward contracts. Before the PX could do so, on February 2, 2001, the state seized the contracts. On September 20, 2001, a federal appeals court ruled that the governor of California acted illegally when he seized the power contracts held by SCE. In conjunction with its settlement agreement with the CPUC (discussed in CPUC Litigation Settlement Agreement), SCE has agreed to release any claim for compensation against the state for these contracts. However, if the PX prevails in its claims against the state, SCE may receive some refunds. Due to its speculative grade credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and some of the existing contracts were terminated by the counterparties.

Regulatory Environment

SCE operates in a highly regulated environment and has an exclusive franchise within its service territory. SCE has an obligation to deliver electric service to its customers and regulatory authorities have an obligation to provide just and reasonable rates. In the mid-1990s, state lawmakers and the CPUC initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its gas-fired generation portfolio. Today, independent power companies own the divested generating plants. The electric industry restructuring plan also instituted a multi-year freeze on the rates that SCE could charge its customers and transition cost recovery mechanisms (as described in Status of Transition and Power-Procurement Cost Recovery) designed to allow SCE to recover its stranded costs associated with generation-related assets. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between

1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates (except for the surcharge effective in 2001) were to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations are recovered. However, between May 2000 and June 2001, the prices charged by sellers of power escalated far beyond what SCE could charge its customers. As a result, SCE incurred $2.7 billion (after tax), or $4.7 billion (pre-tax), in write-offs as of December 31, 2000, and net undercollected transition costs through August 31, 2001. As indicated below, implementation of the CPUC settlement agreement and CPUC approval of SCE's Utility-Retained Generation (URG) application is expected to allow SCE to recover substantially all of the $4.7 billion.

Generation and Power Procurement

During the rate freeze, recovery of generation-related transition costs was tracked through the TCBA mechanism. Revenue from generation-related operations was determined through the market and transition cost recovery mechanisms, which included the nuclear rate-making agreements. During fourth quarter 2001, the TCBA mechanism was terminated retroactive to September 1, 2001, and a $3.6 billion PROACT regulatory asset was created in accordance with the October 2001 settlement agreement with the CPUC and the PROACT resolution adopted in January 2002. In accordance with a state law passed in January 2001, SCE will continue to own its remaining generation assets, which will be subject to cost-based ratemaking, through 2006 (see further discussion in URG Proceeding).

Through December 31, 2000, SCE had been recovering its investment in its nuclear facilities on an accelerated basis (over four years) in exchange for a lower authorized rate of return on investment. SCE's nuclear assets were earning an annual rate of return on investment of 7.35%. However, due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power-Procurement Cost Recovery), as of December 31, 2000, SCE was no longer able to conclude that the $610 million balance of unamortized nuclear investment regulatory assets was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time (see further discussion in Earnings). Should the URG application be approved, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and related flow-through taxes retroactive to August 31, 2001, with recovery based on a 10-year period, effective January 1, 2001, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance as necessary to reflect recovery of the nuclear investment in accordance with the final URG decision.

The San Onofre incentive-pricing plan authorizes a fixed rate of approximately 4¢ per kWh generated for operating costs including incremental capital costs, nuclear fuel and nuclear fuel financing costs. The San Onofre incentive-pricing plan started in April 1996 and ends in December 2003. The Palo Verde Nuclear Generating Station's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, were subject to balancing account treatment. The Palo Verde plan started in January 1997 and was to end in December 2001. The benefits of operation of the San Onofre units and the Palo Verde units were required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. In a June 2001 decision, the CPUC granted SCE's request to eliminate the San Onofre post-2003 sharing mechanism based on compliance with a state law enacted in early 2001. In a September 2001 decision, the CPUC granted SCE's request to eliminate the Palo Verde post-2001 sharing mechanism and to continue the current rate-making treatment for Palo Verde, including the continuation of the existing nuclear incentive procedure with a 5¢ per kWh cap on replacement power costs, until resolution of SCE's next general rate case or further CPUC action. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the TCBA mechanism. These rate-making plans and the TCBA mechanism were to continue for rate-making purposes at least through the end of the rate freeze period. However, in its URG application, SCE proposed to move the recovery of nuclear costs to another balancing account mechanism. See discussion in URG Proceeding for the proposed and alternate decisions' impact on the incentive-pricing plans.

CPUC Litigation Settlement Agreement

In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its past electricity procurement costs in accordance with the tariffs filed with the FERC. By agreement of the parties, a stay of the lawsuit was issued in April 2001 while SCE sought implementation of legislative, regulatory and executive actions to resolve the California energy crisis and SCE's related financial and liquidity problems. In October 2001, the federal district court entered a stipulated judgment approving an agreement between the CPUC and SCE to settle the pending lawsuit. On January 23, 2002, the CPUC adopted a resolution implementing the settlement agreement. See discussion below in PROACT Regulatory Asset.

Key elements of the settlement agreement include the following items:

- Establishment of the PROACT, as of September 1, 2001, with an opening balance equal to the amount of SCE's procurement-related liabilities as of August 31, 2001 (approximately $6.4 billion), less SCE's cash and cash equivalents as of that date (approximately $2.5 billion), and less $300 million.

- Beginning on September 1, 2001, SCE will apply to the PROACT, on a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. Unrecovered obligations in the PROACT will accrue interest from September 1, 2001.

- Maintain current rates (including surcharges) in effect until December 31, 2003, subject to certain adjustments, or, if earlier, until the date that SCE recovers the entire PROACT balance. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years. The parties project that existing retail electric rates, including surcharges and as adjusted to reflect certain costs, will likely result in SCE recovering substantially all of its unrecovered procurement-related obligations prior to the end of 2003.

- If the CPUC concludes that it is desirable to authorize a securitized financing of SCE's procurement-related obligations, the parties will work together to achieve the securitization. Proceeds of any securitization will be credited to the PROACT when they are actually received.

- During the period that SCE is recovering its previously incurred procurement-related obligations, no penalty will be imposed by the CPUC on SCE for any noncompliance with CPUC-mandated capital structure requirements.

- SCE can incur up to $250 million of recoverable costs to acquire financial instruments and engage in other transactions intended to hedge fuel cost risks associated with SCE's retained generation assets and power purchase contracts with QFs and other utilities. As of December 31, 2001, SCE had purchased $209 million in hedging instruments. See discussion in Market Risk Exposures.

- SCE will not declare or pay dividends or other distributions on its common stock (all of which is held by its parent) prior to the earlier of the date SCE has recovered all of its procurement-related obligations in the PROACT or January 1, 2005. However, if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends, and the CPUC will not unreasonably withhold its consent.

- To ensure the ability of SCE to continue to provide adequate service, SCE may make capital expenditures above the level contained in current rates, up to $900 million per year, which will be treated as recoverable costs.

- Subject to certain qualifications, SCE will cooperate with the CPUC and the California Attorney General to pursue and resolve SCE's claims and rights against sellers of energy and related services, SCE's defenses to claims arising from any failure to make payments to the PX or ISO, and similar claims by the State of California or its agencies against the same adverse parties. During the recovery period discussed above, refunds obtained by SCE related to its procurement-related liabilities will be applied to the balance in the PROACT.

The settlement agreement states that one of its purposes is to restore the investment grade creditworthiness of SCE as rapidly as reasonably practicable so that it will be able to provide reliable electrical service as a state-regulated entity as it has in the past. SCE cannot provide assurance that it will regain investment grade credit ratings by any particular date.

On November 28, 2001, a federal court of appeals denied a California consumer group's request for a long-term stay of the settlement. The group had alleged that it was denied due process and that the CPUC had no authority to agree with SCE to violate the statutory rate freeze. In its ruling, the federal court of appeals also granted SCE's request for an expedited hearing of an appeal of the settlement filed by the consumer group. On March 4, 2002, the court of appeals heard argument on the appeal and the matter is now under submission. A decision could be issued anytime during the next several months. SCE cannot predict the outcome of the appeal or the impact that any outcome would have upon the stipulated judgment or the settlement, at this time. Possible outcomes include affirmance, a return to the district court or reversal of the stipulated judgment. SCE cannot predict whether or how a ruling on the stipulated judgment could also affect the settlement agreement.

PROACT Regulatory Asset

According to the terms of the settlement agreement and the CPUC resolution, in the fourth quarter of 2001, SCE established (retroactive to August 31, 2001) a $3.6 billion PROACT regulatory asset for its previously incurred procurement costs.

The beginning balance of the PROACT, as verified by the CPUC, was calculated as follows:

In millions	
Past-due bills:	
PX or ISO	$ 924
QFs	1,219
PX energy credits	236
Imbalance energy (CDWR)	383
Ancillary services for resale cities	30
Total past-due bills	2,792
Procurement-related debt (including accrued interest):	
Credit facilities	1,298
Bilateral credit facilities	415
Defaulted commercial paper	563
Floating rate notes due May 2002	313
Variable rate notes due November 2003	1,043
Total procurement-related debt	3,632
Total procurement-related liabilities	6,424
Less: Cash and cash equivalents on hand	(2,547)
Less: Amount stipulated in agreement	(300)
Net PROACT balance as of August 31, 2001	**$ 3,577**

For a comparison between the PROACT balance as of August 31, 2001, and the TCBA balance as of that date, see discussion in Status of Transition and Power-Procurement Cost Recovery.

CDWR Power Purchases

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR and through the ISO are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, Assembly Bill 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue bonds to finance electricity purchases.

On March 27, 2001, the CPUC issued an interim order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢-per-kWh surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which increased to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢-surcharge discussed in Rate Stabilization Proceedings), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late.

On February 21, 2002, the CPUC issued a decision implementing a CDWR revenue requirement of $9.0 billion to pay its bonds' costs and energy procurement costs for the period January 17, 2001, through December 31, 2002. The decision states that SCE's allocated share of this revenue requirement would be approximately $3.6 billion, and changes SCE's payment to 9.744¢ per kWh for all bills rendered on or after March 15, 2002. The decision requires SCE to pay the CDWR in equal monthly installments over a six-month period the difference in rates between January 17, 2001, and March 15, 2002. SCE estimates that this amount could be approximately $41 million.

On February 28, 2002, SCE and the CDWR executed an agreement that resolves outstanding issues relating to the payment for electric power purchased for SCE's customers through the ISO real-time market (known as imbalance energy). Under this agreement, SCE will pay the CDWR for imbalance energy previously delivered in three installments ($100 million on April 1, 2002; $150 million on June 3, 2002; and the balance on July 1, 2002).

Status of Transition and Power-Procurement Cost Recovery

SCE's transition costs to be recovered through the TCBA mechanism included power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and other costs incurred to provide service to customers. Other costs included the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs and accelerated recovery of investment in nuclear generating units. Recovery of costs related to power-purchase QF contracts was permitted through the terms of each contract. Legislation and regulatory decisions issued prior to the beginning of the rate freeze called for most of the remaining transition costs to be recovered through the end of the four-year transition period (not later than March 31, 2002). Because regulatory and legislative actions that make such recovery probable were not taken in a timely manner during the energy crisis, as of December 31, 2000, SCE was unable to conclude that the net regulatory assets related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other generation regulatory assets were probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings at that time (see further discussion in Earnings).

There were three sources of revenue available to SCE for transition cost recovery through the TCBA mechanism: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets and competition transition charge (CTC) revenue. Revenue from the first two sources has not been available since January 2001. Net proceeds of the 1998 plant sales were used to reduce transition costs, which otherwise had been expected to be collected through the TCBA mechanism. However, state legislation enacted in January 2001 prohibits the sale of SCE's remaining generation assets until 2006. SCE stopped selling power from its generation into the ISO and PX markets in January 2001, after SCE's credit ratings were downgraded and the PX suspended SCE's trading privileges (see discussion in Generation and Power Procurement).

CTC revenue was determined residually (i.e., CTC revenue was the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applied to all customers who were using or began using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue was calculated through the TRA mechanism. In accordance with the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue was transferred from the TRA to the TCBA on a monthly basis, retroactive to January 1, 1998 (see further discussion in Rate Stabilization Proceedings). A previous decision had called only for a transfer of positive residual CTC revenue (TRA overcollections) to the TCBA and there had not been any positive residual CTC revenue between May 2000 and June 2001.

Because the regulatory and legislative actions that made such recovery probable were not taken, SCE was unable to conclude as of December 31, 2000, that the recalculated TCBA net undercollection was probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of that date (see further discussion in Earnings), and an additional $552 million (pre-tax) of net undercollected transition costs was charged to earnings between January 1, 2001, and August 31, 2001. Although the TCBA was written off, SCE continued to calculate the account for rate-making purposes, and the account reflected a $4.2 billion undercollection as of August 31, 2001, the effective date of the beginning of the PROACT mechanism and the end of the TCBA mechanism. If the TCBA would have been adjusted for the impact of SCE's treatment of the nuclear facilities as proposed in the URG proceeding, the TCBA balance as of August 31, 2001, would have reflected an undercollection of $3.626 billion, substantially equal to the $3.577 billion undercollection in the PROACT regulatory asset.

For more details on the matters discussed above, see discussions in Rate Stabilization Proceedings, URG Proceeding and PROACT Regulatory Asset.

Litigation

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit involves securities fraud claims arising from alleged improper accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock between July 21, 2000, and April 17, 2001. This lawsuit has been consolidated with another similar lawsuit filed on March 15, 2001. A consolidated class action complaint was filed on August 3, 2001. On September 17, 2001, SCE and Edison International filed a motion to dismiss for failure to state a claim. On March 8, 2002, the district court issued an order dismissing the complaint with prejudice. The plaintiffs could appeal this ruling to the court of appeals.

In addition to the lawsuits filed against Edison International and SCE discussed above, SCE has been a defendant in a number of legal actions brought by various QFs arising out of SCE's suspension of payments for electricity delivered by the QFs during the period November 1, 2000, through March 26, 2001. The QF claims were eventually largely subsumed within agreements with the litigating QFs providing for a provisional settlement of the parties' disputes. On March 1, 2002, SCE paid the amounts due under settlement agreements with these QFs, which triggered the releases and other provisions of the settlements. As a result, the litigation with those QFs to whom payment in full has been made under the parties' settlement agreements should be dismissed during 2002. However, SCE's March 1, 2002, payments excluded several QFs or did not result in immediate releases under the settlement agreements based on unique disputes or other unique circumstances, including the status of regulatory approval.

Rate Stabilization Proceedings

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the four-year rate freeze was to end on March 31, 2002, or earlier, depending on the pace of transition cost recovery. In December 2000, SCE filed an amended rate stabilization plan application, stating that the statutory rate freeze had ended in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001.

In January 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covered, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. In April 2001, the CPUC adopted an order instituting investigation that reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. The CPUC ordered testimony and briefing on these matters, which SCE filed in May and June 2001. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. On February 11, 2002, SCE filed an application for rehearing of the decision stating that the decision is an unlawful and erroneous attempt to rewrite the first priority condition rather than interpret it and that the decision would result in higher rates for SCE's customers. SCE cannot predict what effects this investigation or any subsequent actions by the CPUC may have on SCE.

In March 2001, the CPUC ordered a rate increase in the form of a 3¢-per-kWh surcharge applied only to going-forward electric power procurement costs and affirmed that a 1¢ interim surcharge granted in January 2001 is permanent. The 3¢ surcharge is to be added to the rate paid to the CDWR (see CDWR Power Purchases). Although the 3¢-increase was authorized as of March 27, 2001, the surcharge was not collected in rates until the CPUC established a rate design in early June 2001. To compensate for the two-month delay in collecting the 3¢ surcharge, the CPUC authorized an additional ½¢ surcharge for a 12-month period beginning in June 2001.

URG Proceeding

In June 2001, SCE filed a comprehensive proposal for new cost-of-service ratemaking for utility retained generation through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined by the general rate case. The URG proposal calls for balancing accounts for SCE-owned generation, QF and interutility contracts, procurement costs and ISO charges based on either actual or CPUC-authorized revenue requirements. Under the proposal, the four new balancing accounts would be effective January 1, 2001, for capital-related costs, and February 1, 2001, for non-capital-related costs. In addition, SCE's unamortized nuclear investment would be amortized and recovered in rates over a 10-year period, effective January 1, 2001. Should this application be approved as filed, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and regulatory assets related to purchased-power settlements and flow-through taxes, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance in accordance with the final URG decision.

On January 18, 2002, a CPUC administrative law judge issued a proposed decision and a CPUC commissioner issued an alternate proposed decision. Both the proposed and alternate proposed decisions adopt most of the elements of SCE's application, but propose eliminating an incentive-pricing plan for San Onofre, effective January 1, 2002, and replacing it with balancing account treatment for San Onofre's operating costs, subject to a later reasonableness review. On February 7, 2002, another CPUC commissioner issued an alternate proposed decision recommending continuing the incentive-pricing plan for San Onofre Units 2 and 3 through December 31, 2003, as originally provided in CPUC decisions adopted in early 1996. A final decision is expected in second quarter 2002.

Generation Procurement Proceeding

In October 2001, the CPUC issued an order instituting rulemaking (OIR) to establish policies and cost recovery mechanisms for generation procurement. The OIR directed SCE and the other major California electric utilities to provide recommendations for establishing these policies and mechanisms to enable the utilities to resume their power procurement responsibilities in 2003. In comments filed with the CPUC on November 26, 2001, SCE recommended that the CPUC issue a procurement framework decision in February 2002, and direct the utilities to submit their specific procurement plan proposals and related framework compliance proposals in March 2002. SCE also proposed that a final decision be issued in October 2002 adopting utility-specific procurement plans. The CPUC has not yet acted on SCE's recommendations, but is expected in second quarter 2002 to issue a scoping memo setting forth issues to be addressed in this proceeding.

Accounting for Generation-Related Assets and Power Procurement Costs

In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its generation assets. At that time, SCE did not write off any of its generation-related assets, including related regulatory assets, because the electric utility industry restructuring plan made probable their recovery through a non-bypassable charge to distribution customers.

During the second quarter of 1998, in accordance with asset impairment accounting standards, SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

As of December 31, 2000, SCE assessed the probability of recovery of its generation-related assets and power procurement costs in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, and could not conclude that its $2.9 billion TCBA undercollection (as redefined in the March 27 decisions) and $1.3 billion (book value) of its net generation-related regulatory assets to be amortized into the TCBA, were probable of recovery through the rate-making process. As a result, accounting principles generally accepted in the United States required that the balances in the accounts be written off as a charge to earnings. In addition to the $4.2 billion pre-tax write-off, SCE incurred approximately $552 million (pre-tax) in net undercollected transition costs through August 31, 2001 (see Earnings).

In accordance with the CPUC settlement agreement and the PROACT resolution, in fourth quarter 2001, SCE established a $3.6 billion regulatory asset for previously incurred power procurement costs, called the PROACT, retroactive to August 31, 2001. See further discussion in PROACT Regulatory Asset. CPUC approval of the URG application, as filed (see URG Proceeding), together with implementation of the PROACT mechanism is expected to allow SCE to recover substantially all of the $4.7 billion in write-offs as of December 31, 2000, and net undercollected transition costs incurred through August 31, 2001.

If the CPUC approves SCE's URG application, as filed, SCE expects to reapply accounting principles for rate-regulated enterprises for its generation assets. These assets will then be subject to traditional cost-of-service regulation.

Distribution

Revenue related to distribution operations is determined through a performance-based rate-making (PBR) mechanism and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return on investment. Key elements of the distribution PBR include: distribution rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a utility bond index; standards for customer satisfaction; service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from distribution operations. The distribution PBR was to have ended in December 2001, but in June 2001 the CPUC extended the mechanism until SCE's next general rate case, which will be effective in 2003. A CPUC proposed decision on the PBR mechanism for 2002 was issued in January 2002. The proposed decision authorized SCE to use a formula to determine its distribution revenue requirement for the last half of 2001 and 2002, and a revenue balancing account to ensure that variations in sales do not result in under or overcollections. A final decision is expected in second quarter 2002. At this time, SCE cannot predict the effect of the final decision on its results of operations.

In December 2001, SCE filed its 2003 general rate case with the CPUC, requesting an increase of approximately $500 million in revenue (compared to 2000 recorded revenue) for its distribution and generation operations. Hearings are expected to begin in July 2002, with a final decision expected in second quarter 2003.

Transmission

Transmission revenue is determined through FERC-authorized rates and is subject to refund.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. In December 2000, the FERC took limited action and failed to impose a price cap. SCE filed an emergency petition in the federal court of appeals challenging the FERC order and requesting the FERC to immediately establish cost-based wholesale rates. The court denied SCE’s petition in January 2001.

In its December 2000 order, the FERC established an underscheduling penalty effective January 1, 2001, applicable to scheduling coordinators that do not schedule sufficient resources to supply 95% of their respective loads. In December 2001, the FERC eliminated the underscheduling penalty retroactive to January 1, 2001.

On April 25, 2001, after months of extremely high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region. The latest order is in effect until September 30, 2002.

After unsuccessful settlement negotiations among utilities, power sellers and state representatives, on July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges to the ISO and PX spot markets during the period from October 2, 2000, through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge will conduct evidentiary hearings on this matter. SCE cannot predict the amount of any potential refunds. Under the settlement of litigation with the CPUC, refunds will be applied to the balance in the PROACT.

Environmental Protection

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.

As further discussed in Note 12 to the Consolidated Financial Statements, SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE’s recorded estimated minimum liability to remediate its 42 identified sites is $111 million. SCE believes that, due to uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $279 million. In 1998, SCE sold all of its gas-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $50 million of its recorded liability, through an incentive mechanism, which is discussed in Note 12. SCE has recorded a regulatory asset of $76 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. As a result, 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 $10 million to $25 million. Recorded costs for the year ended December 31, 2001, were $18 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 and, based upon the CPUC's regulatory treatment of environmental-cleanup 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.

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). A study was undertaken to determine the specific impact of air contaminant emissions from the Mohave Generating Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. In June 1999, the Environmental Protection Agency (EPA) issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. The EPA issued its final rule on February 8, 2002, which incorporates the terms of the consent decree into the visibility provisions of its Federal Implementation Plan for Nevada, making the terms of the consent decree federally enforceable.

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of the Mohave station is estimated to be approximately $560 million over the next four years. However, SCE has suspended its efforts to seek approval to install the Mohave controls because it has not obtained reasonable assurance of an adequate coal supply for operating Mohave beyond 2005. If an adequate coal supply is not obtained, it will become necessary to shut down the Mohave station after December 31, 2005. If the station is shut down at that time, the shutdown is not expected to have a material adverse impact on SCE's financial position or results of operations, assuming the remaining book value of the station (approximately $88 million as of December 31, 2001), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict what effect any future actions by the CPUC may have on this matter.

SCE's projected environmental capital expenditures are $1.3 billion for the 2002–2006 period, mainly for undergrounding certain transmission and distribution lines.

San Onofre Nuclear Generating Station

In February 2001, SCE's San Onofre Unit 3 experienced a fire due to an electrical fault in the non-nuclear portion of the plant. The turbine rotors, bearings and other components of the turbine generator system were damaged extensively. In June 2001, Unit 3 returned to service. Under the currently effective San Onofre rate-recovery plan (discussed in the Generation and Power Procurement section of Regulatory Environment), SCE's lost revenue was approximately $98 million as a result of the fire and related outage.

The San Onofre Units 2 and 3 steam generators' design allows for the removal of up to 10% of the tubes before the rated capacity of the unit must be reduced. Increased tube degradation was found during routine inspections in 1997. To date, 8% of Unit 2's tubes and 6% of Unit 3's tubes have been removed from service. A decreasing (favorable) trend in degradation has been observed in more recent inspections.

Critical Accounting Policies

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

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, where 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 a cost that would otherwise be charged to expense by a non-regulated 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. See further discussion of regulatory assets and liabilities in Note 1 to the Consolidated Financial Statements.

SCE applied judgment in the use of the above principles when it concluded, as of December 31, 2000, that $4.2 billion of generation-related regulatory assets and liabilities were no longer probable of recovery, and wrote off these assets as a charge to earnings, and again in fourth quarter 2001 when it created the $3.6 billion PROACT regulatory asset with a corresponding credit to earnings upon receiving regulatory assurance of collection of these costs. See further discussion in Earnings section.

New Accounting Standards

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. The standard requires derivatives to be recognized on the balance sheet at fair value, unless they meet the definition of a normal purchase or sale. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of the hedge. For a hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's equity under the caption accumulated other comprehensive income, and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately. SCE does not anticipate any earnings impact from any derivatives, since it expects that any market price changes will be recovered in rates. In October 2001, additional implementation guidance, which will be effective April 1, 2002, was issued. SCE is still evaluating the impact of this new implementation guidance.

In July and August 2001, three new accounting standards were issued: Business Combinations; Goodwill and Other Intangibles; and Accounting for Asset Retirement Obligations.

The new Business Combinations standard eliminates the pooling-of-interests method, effective June 30, 2001. After that, all business combinations will be recorded under the purchase method (i.e., record purchase based upon value exchanged and record goodwill for excess of costs over the net assets acquired).

The new Goodwill and Other Intangibles standard requires that companies cease amortizing goodwill, effective January 1, 2002. Goodwill initially recognized after June 30, 2001, will not be amortized. Goodwill on the balance sheet at June 30, 2001, was amortized until December 31, 2001. Under the new standard, goodwill will be tested for impairment using a fair-value approach when events or circumstances occur indicating that impairment might exist. Also, a benchmark assessment for goodwill is required within six months of the date of adoption of the standard.

The Accounting for Asset Retirement Obligations standard requires entities to record the fair value of a liability for a legal asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. The standard is effective for SCE beginning on January 1, 2003.

SCE is studying the impact of the new Asset Retirement Obligations standard and is unable to predict at this time the effect on its financial statements. SCE does not anticipate any material impact on its results of operations or financial position from the other two new accounting standards.

In October 2001, a new accounting standard was issued related to accounting for the impairment or disposal of long-lived assets. Although the standard supersedes a prior accounting standard related to the impairment of long-lived assets, it retains the fundamental provisions of the impairment standard regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under the new accounting standard, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). The standard (effective on January 1, 2002) was adopted early, in fourth quarter 2001. The adoption of this standard had no effect on SCE's financial statements.

Forward-looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of important factors that may be outside SCE's control, including among other things: the outcome of the pending appeals of the stipulated judgment approving the settlement agreement with the CPUC, and the effects of other legal actions or ballot initiatives, if any, attempting to undermine the provisions of the settlement agreement or otherwise adversely affecting SCE; changes in prices of wholesale electricity and natural gas or in SCE's operating costs, which could cause SCE's cost recovery to be less than anticipated; the actions of securities rating agencies, including the determination of whether or when to make changes in SCE's credit ratings, the ability of SCE to regain investment grade ratings, and the impact of current or lowered ratings and other financial market conditions on the ability of SCE to obtain needed financing on reasonable terms; further actions by state and federal regulatory bodies setting rates, adopting or modifying cost recovery, accounting or rate-setting mechanisms and implementing the restructuring of the electric utility industry, as well as legislative or judicial actions affecting the same matters; the effects of increased competition in energy-related businesses, including the market entrants and the effects of new technologies that may be developed in the future; new or increased environmental liabilities; and weather conditions, natural disasters, and other unforeseen events.

Consolidated Statements of Income (Loss)

In millions Year ended December 31,	2001	2000	1999
Operating revenue	**$ 8,126**	$ 7,870	$ 7,548
Fuel	**212**	195	215
Purchased power	**3,770**	4,687	3,190
Provisions for regulatory adjustment clauses – net	**(3,028)**	2,301	(763)
Other operation and maintenance	**1,771**	1,772	1,933
Depreciation, decommissioning and amortization	**681**	1,473	1,548
Property and other taxes	**112**	126	122
Net gain on sale of utility plant	**(9)**	(25)	(3)
Total operating expenses	**3,509**	10,529	6,242
Operating income (loss)	**4,617**	(2,659)	1,306
Interest and dividend income	**215**	173	69
Other nonoperating income	**57**	118	162
Interest expense – net of amounts capitalized	**(785)**	(572)	(483)
Other nonoperating deductions	**(38)**	(110)	(107)
Income (loss) before taxes	**4,066**	(3,050)	947
Income tax (benefit)	**1,658**	(1,022)	438
Net income (loss)	**2,408**	(2,028)	509
Dividends on preferred stock	**22**	22	25
Net income (loss) available for common stock	**$ 2,386**	$ (2,050)	**$** 484

Consolidated Statements of Comprehensive Income (Loss)

In millions Year ended December 31,	2001	2000	1999
Net income (loss)	**$ 2,408**	$ (2,028)	$ 509
Other comprehensive income, net of tax:			
Unrealized gain on securities – net	**—**	3	28
Cumulative effect of change in accounting for derivatives	**398**	—	—
Unrealized loss on cash flow hedges	**(420)**	—	—
Reclassification adjustment for loss included in net income (loss)	**—**	(25)	(45)
Comprehensive income (loss)	**$ 2,386**	$ (2,050)	$ 492

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

Consolidated Balance Sheets

In millions December 31,	2001	2000
ASSETS		
Cash and equivalents	**$ 3,414**	$ 583
Receivables, less allowances of $32 and $23 for uncollectible accounts at respective dates	**1,093**	919
Accrued unbilled revenue	**451**	377
Fuel inventory	**14**	12
Materials and supplies, at average cost	**146**	132
Accumulated deferred income taxes – net	**433**	545
Regulatory assets – net	**83**	—
Prepayments and other current assets	**145**	124
Total current assets	**5,779**	2,692
Nonutility property – less accumulated provision for depreciation of $17 and $11 at respective dates	**159**	102
Nuclear decommissioning trusts	**2,275**	2,505
Other investments	**224**	90
Total investments and other assets	**2,658**	2,697
Utility plant, at original cost:		
Transmission and distribution	**13,568**	13,129
Generation	**1,729**	1,745
Accumulated provision for depreciation and decommissioning	**(7,969)**	(7,834)
Construction work in progress	**556**	636
Nuclear fuel, at amortized cost	**129**	143
Total utility plant	**8,013**	7,819
Regulatory assets – net	**5,528**	2,390
Other deferred charges	**475**	368
Total deferred charges	**6,003**	2,758
Total assets	**$ 22,453**	$ 15,966

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

Southern California Edison Company

In millions, except share amounts December 31,	**2001**	2000
LIABILITIES AND SHAREHOLDER'S EQUITY		
Short-term debt	**$ 2,127**	$ 1,451
Long-term debt due within one year	**1,146**	646
Preferred stock to be redeemed within one year	**105**	—
Accounts payable	**3,261**	1,055
Accrued taxes	**823**	536
Regulatory liabilities – net	**—**	195
Other current liabilities	**1,645**	1,502
Total current liabilities	**9,107**	5,385
Long-term debt	**4,739**	5,631
Accumulated deferred income taxes – net	**3,365**	2,009
Accumulated deferred investment tax credits	**153**	164
Customer advances and other deferred credits	**739**	722
Power-purchase contracts	**356**	467
Accumulated provision for pensions and benefits	**420**	296
Other long-term liabilities	**148**	127
Total deferred credits and other liabilities	**5,181**	3,785
Commitments and contingencies (Notes 3, 11 and 12)		
Preferred stock:		
Not subject to mandatory redemption	**129**	129
Subject to mandatory redemption	**151**	256
Total preferred stock	**280**	385
Common stock (434,888,104 shares outstanding at each date)	**2,168**	2,168
Additional paid-in capital	**336**	334
Accumulated other comprehensive income (loss)	**(22)**	—
Retained earnings (deficit)	**664**	(1,722)
Total common shareholder's equity	**3,146**	780
Total liabilities and shareholder's equity	**$ 22,453**	$ 15,966

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

Consolidated Statements of Cash Flows

In millions Year ended December 31,	**2001**	2000	1999
Cash flows from operating activities:			
Net income (loss)	**$ 2,408**	$ (2,028)	$ 509
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**681**	1,473	1,548
Other amortization	**82**	97	95
Deferred income taxes and investment tax credits	**1,313**	(928)	178
Regulatory assets – long-term – net	**(3,135)**	1,759	(1,354)
Gas call options	**(91)**	20	11
Net gain on sale of marketable securities	**—**	(41)	(77)
Other assets	**(68)**	24	(73)
Other liabilities	**17**	(13)	17
Changes in working capital:			
Receivables and accrued unbilled revenue	**(243)**	(282)	99
Regulatory liabilities – short-term – net	**(278)**	97	363
Fuel inventory, materials and supplies	**(16)**	29	(5)
Prepayments and other current assets	**(21)**	(14)	(19)
Accrued interest and taxes	**365**	48	(186)
Accounts payable and other current liabilities	**2,251**	588	352
Net cash provided by operating activities	**3,265**	829	1,458
Cash flows from financing activities:			
Long-term debt issued	**—**	1,760	491
Long-term debt repaid	**—**	(525)	(363)
Bonds repurchased and funds held in trust	**(130)**	(440)	—
Rate reduction notes repaid	**(246)**	(246)	(246)
Nuclear fuel financing – net	**(21)**	9	(37)
Short-term debt financing – net	**676**	655	326
Dividends paid	**(1)**	(395)	(686)
Net cash provided (used) by financing activities	**278**	818	(515)
Cash flows from investing activities:			
Additions to property and plant	**(688)**	(1,096)	(986)
Funding of nuclear decommissioning trusts	**(36)**	(69)	(116)
Proceeds from sales of marketable securities	**—**	41	84
Sales of investments in other assets	**12**	34	19
Net cash used by investing activities	**(712)**	(1,090)	(999)
Net increase (decrease) in cash and equivalents	**2,831**	557	(56)
Cash and equivalents, beginning of year	**583**	26	82
Cash and equivalents, end of year	**$ 3,414**	$ 583	$ 26
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 455**	$ 303	$ 287
Tax payments (receipts)	**(105)**	306	433

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

Consolidated Statements of Changes in Common Shareholder's Equity

Southern California Edison Company

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Common Shareholder's Equity
Balance at December 31, 1998	$ 2,168	$ 334	$ 39	$ 794	$ 3,335
Net income				509	509
Unrealized gain on securities			46		46
Tax effect			(18)		(18)
Reclassified adjustment for gain included in net income			(77)		(77)
Tax effect			32		32
Dividends declared on common stock				(666)	(666)
Dividends declared on preferred stock				(25)	(25)
Stock option appreciation				(3)	(3)
Capital stock expense and other		1		(1)	—
Balance at December 31, 1999	$ 2,168	$ 335	$ 22	$ 608	$ 3,133
Net income (loss)				(2,028)	(2,028)
Unrealized gain on securities			8		8
Tax effect			(5)		(5)
Reclassified adjustment for gain included in net income			(41)		(41)
Tax effect			16		16
Dividends declared on common stock				(279)	(279)
Dividends declared on preferred stock				(22)	(22)
Stock option appreciation				(1)	(1)
Capital stock expense and other		(1)			(1)
Balance at December 31, 2000	$ 2,168	$ 334	$ —	$ (1,722)	$ 780
Net income				2,408	2,408
Cumulative effect of change in accounting for derivatives			398		398
Unrealized loss on cash flow hedges			(420)		(420)
Dividends accrued on preferred stock				(22)	(22)
Capital stock expense and other		2			2
Balance at December 31, 2001	$ 2,168	$ 336	$ (22)	$ 664	$ 3,146

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

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

Notes to Consolidated Financial Statements

Note 1. Summary of Significant Accounting Policies

Nature of Operations

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.

SCE operates in a highly regulated environment and has an exclusive franchise within its service territory. SCE has an obligation to deliver electric service to its customers and regulatory authorities have an obligation to provide just and reasonable rates. In the mid-1990s, state lawmakers and the California Public Utilities Commission (CPUC) initiated an electric industry restructuring process. SCE, as directed by the CPUC, sold its gas-fired generating stations. See Note 3 for a further discussion of regulatory changes in the electric utility industry.

Basis of Presentation

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated. Certain prior-year amounts were reclassified to conform to the December 31, 2001, financial statement presentation.

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 CPUC and the Federal Energy Regulatory Commission (FERC). Since 1997, as a result of industry restructuring legislation enacted by the State of California and related changes in the rate recovery of generation-related assets, SCE has used accounting principles applicable to enterprises in general for its investment in generation facilities.

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 disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to regulatory matters, financial instruments, decommissioning and contingencies are further discussed in Notes 3, 4, 11 and 12 to the Consolidated Financial Statements, respectively.

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

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year. Since January 17, 2001, power purchased by the California Department of Water Resources (CDWR) or through the Independent System Operator (ISO) for SCE's customers is not considered a cost to SCE, since SCE is acting as an agent for these transactions. Further, amounts billed to ($2.0 billion in 2001) and collected from its customers for these power purchases are being remitted to the CDWR and are not recognized as revenue to SCE. See further discussion in Note 3.

Related Party Transactions

Certain Edison Mission Energy (a wholly owned subsidiary of Edison International) subsidiaries have 49% - 50% ownership in partnerships (qualifying facilities (QFs)) that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. SCE's purchases from these partnerships were $983 million in 2001, $716 million in 2000 and $513 million in 1999.

Purchased Power

SCE purchased power through the California Power Exchange (PX) from April 1998 through mid-January 2001. SCE has bilateral forward contracts with other entities (as discussed in Note 4) and power-purchase contracts with other utilities and independent power producers classified as QFs. Purchased power detail is provided below:

In millions Year ended December 31,	**2001**	2000	1999
PX/ISO:			
Purchases	**$ 775**	$ 8,449	$ 2,490
Generation sales	**324**	6,120	1,719
Purchased power – PX/ISO – net	**451**	2,329	771
Purchased power – bilateral contracts	**188**	—	—
Purchased power – interutility/QF contracts	**3,131**	2,358	2,419
Total	**$ 3,770**	$ 4,687	$ 3,190

Since January 17, 2001, all other power is purchased by the CDWR for delivery to SCE's customers and is not considered a cost to SCE.

Planned Major Maintenance

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

Other Nonoperating Income and Deductions

Other nonoperating income and deductions was comprised of:

In millions Year ended December 31,	**2001**	2000	1999
Gain on sale of marketable securities	**$ —**	$ 41	$ 77
AFUDC	**16**	21	24
Other	**41**	56	61
Total other nonoperating income	**$ 57**	$ 118	$ 162
Provisions for regulatory issues and refunds	**$ 7**	$ 78	$ 79
Other	**31**	32	28
Total other nonoperating deductions	**$ 38**	$ 110	$ 107

Cash Equivalents

Cash equivalents include time deposits and other investments with original maturities of three months or less. All investments are classified as available for sale.

Fuel Inventory

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

Investments

Net unrealized gains (losses) on equity investments are recorded as a separate component of shareholder's equity under the caption "Accumulated other comprehensive income." Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning. All investments are classified as available-for-sale.

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings in other nonoperating income. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

AFUDC – equity was $7 million in 2001, $11 million in 2000 and $13 million in 1999. AFUDC – debt was $9 million in 2001, $10 million in 2000 and $11 million in 1999.

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.6% for 2001, 2000 and 1999.

SCE's net investment in generation-related utility plant was $1.0 billion at both December 31, 2001, and December 31, 2000.

Nuclear

During the second quarter of 1998, SCE reduced its remaining nuclear plant investment by $2.6 billion (book value as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount in accordance with asset impairment accounting standards. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. The reclassification had no effect on SCE's 1998 results of operations.

SCE had been recovering its investments in San Onofre Nuclear Generating Station Units 2 and 3 and Palo Verde Nuclear Generating Station on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were recovered through an incentive pricing plan that allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price would flow through to the shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were subject to balancing account treatment through December 31, 2001. The San Onofre and Palo Verde rate recovery plans and the Palo Verde balancing account were part of the transition cost balancing account (TCBA).

The nuclear rate-making plans and the TCBA mechanism were to continue for rate-making purposes at least through 2001 for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues (as discussed in Note 3), as of December 31, 2000, SCE was no longer able to conclude that the unamortized nuclear investment was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time. Should SCE's utility-retained generation (URG) application be approved, SCE would reestablish for financial reporting purposes its unamortized nuclear investment and related flow-through taxes, retroactive to August 31, 2001, based on a 10-year recovery period, effective January 1, 2001, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

The benefits of operation of the Palo Verde and San Onofre units were required to be shared equally with ratepayers beginning in 2002 and 2004, respectively. In a June 2001 decision, the CPUC granted SCE's request to eliminate the San Onofre post-2003 benefit sharing mechanism. The CPUC based its action on compliance with a new state law. In a September 2001 decision, the CPUC granted SCE's request to eliminate the Palo Verde post-2001 benefit sharing mechanism and to continue the current rate-making treatment for Palo Verde, including the continuation of the existing nuclear unit incentive procedure with a

5¢ per kWh cap on replacement power costs, until resolution of SCE's next general rate case or further CPUC action. Palo Verde's existing nuclear unit incentive procedure calculates a reward for performance of any unit above an 80% capacity factor for a fuel cycle. See discussion in Note 3 for the proposed and alternate decisions' impact on the incentive pricing plans.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future revenue associated with certain costs that will be recovered from customers through the rate-making process, and regulatory liabilities, which represent probable future reductions in revenue associated with amounts that are to be credited to customers through the rate-making process.

The TCBA was established for the recovery of generation-related transition costs during the four-year rate freeze period. The transition revenue account (TRA) was a CPUC-authorized regulatory asset account in which SCE recorded the difference between revenue received from customers through frozen rates and the costs of providing service to customers, including power procurement costs. SCE's discontinuance of accounting principles for rate-regulated enterprises applicable to its generation assets did not result in a write-off of its generation-related regulatory assets at that time since the CPUC had approved recovery of these assets through the TCBA mechanism.

The gains resulting from the sale of 12 of SCE's generating plants during 1998 have been credited to the TCBA. The coal and hydroelectric generation balancing accounts tracked the differences between market revenue from coal and hydroelectric generation and the plants' operating costs after April 1, 1998.

On March 27, 2001, the CPUC issued a decision stating, among other things, that the rate freeze had not ended, and the TCBA mechanism was to remain in place. However, the decision required SCE to recalculate the TCBA retroactive to January 1, 1998, the beginning of the rate freeze period. The new calculation required the coal and hydroelectric balancing account overcollections (which amounted to $1.5 billion as of December 31, 2000) to be transferred monthly to the TRA, rather than annually to the TCBA (as previously required). In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called only for overcollections to be transferred to the TCBA monthly, while undercollections were to remain in the TRA until they were recovered from future overcollections or the end of the rate freeze, whichever came first.

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

In addition to the TCBA, generation-related regulatory assets totaling $1.3 billion (including the unamortized nuclear investment, flow-through taxes, unamortized loss on sale of plant, purchased-power settlements and other regulatory assets) were written off as of December 31, 2000.

In accordance with an October 2001 settlement agreement between the CPUC and SCE, the CPUC passed a resolution on January 23, 2002, allowing SCE to establish the procurement-related obligations account (PROACT) regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. The settlement agreement calls for the end of the TCBA mechanism as of August 31, 2001, and continuation of the rate freeze (including surcharges) until the earlier of December 31, 2003, or the date SCE recovers its previously incurred (undercollected) power procurement costs. During a period beginning on September 1, 2001, and ending on the earlier of the date that SCE has recovered all of its procurement-related obligations recorded in the PROACT or December 31, 2005, SCE will apply to the

PROACT the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The balance in the PROACT will accrue interest. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years.

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

In millions December 31,	**2001**	2000
PROACT	**$ 2,641**	$ —
Rate reduction notes – transition cost deferral	**1,453**	1,090
Other:		
Flow-through taxes	**1,017**	874
Unamortized loss on reacquired debt	**254**	273
Environmental remediation	**57**	52
Regulatory balancing accounts and other	**189**	(94)
Total	**$ 5,611**	$ 2,195

The regulatory asset related to the rate reduction notes will be recovered over the terms of those notes. The other regulatory assets and liabilities are being recovered through other components of electric rates.

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

New Accounting Standards

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. Adoption of this standard had no material impact on SCE's financial statements. An authoritative accounting interpretation issued in October 2001 precludes fuel contracts that have variable amounts from qualifying under the normal purchases and sales exception effective April 1, 2002. SCE is still evaluating the impact of this new interpretation.

In July and August 2001, three new accounting standards were issued: Business Combinations; Goodwill and Other Intangibles; and Accounting for Asset Retirement Obligations.

The new Business Combinations standard eliminates the pooling-of-interests method, effective June 30, 2001. After that, all business combinations will be recorded under the purchase method (record goodwill for excess of costs over the net assets acquired).

The new Goodwill and Other Intangibles standard requires that companies cease amortizing goodwill, effective January 1, 2002. Goodwill initially recognized after June 30, 2001, was not amortized. Goodwill on the balance sheet at June 30, 2001, was amortized until December 31, 2001. Under the new standard, goodwill will be tested for impairment using a fair-value approach when events or circumstances occur indicating that impairment might exist. Also, a benchmark assessment for goodwill is required within six months of the date of adoption of the standard.

The Accounting for Asset Retirement Obligations standard requires entities to record the fair value of a liability for a legal asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. The standard is effective for SCE on January 1, 2003.

SCE is studying the impact of the new Asset Retirement Obligations standard, and is unable to predict at this time the effect on its financial statements. SCE does not anticipate any material impact on its results of operations or financial position from the Business Combinations and Goodwill and Other Intangibles accounting standards.

In October 2001, a new accounting standard was issued related to accounting for the impairment or disposal of long-lived assets. Although the standard supersedes a prior accounting standard related to the impairment of long-lived assets, it retains the fundamental provisions of the impairment standard regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under the new accounting standard, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). The standard (effective on January 1, 2002) was adopted early, in fourth quarter 2001. The adoption of this new standard had no effect on SCE's financial statements.

Note 2. Liquidity Issues

SCE's liquidity is affected primarily by regulation affecting its ability to recover the cost of power purchases, debt maturities, access to capital markets, credit ratings, dividend payments and capital expenditures. Capital resources include cash from operations and external financings.

Undercollections in the TRA and TCBA mechanisms, coupled with SCE's anticipated near-term capital requirements and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, materially and adversely affected SCE's liquidity throughout 2001. As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, beginning in January 2001, SCE suspended payments owed to the ISO, the PX and QFs, deferred payments of certain obligations for principal and interest on outstanding debt and did not declare dividends on any of its cumulative preferred stock. As applicable, unpaid obligations continued to accrue interest. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. However, since June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. See Note 5. As long as accumulated dividends on SCE's preferred stock remained unpaid, SCE could not pay any dividends on its common stock. Common stock dividends are additionally restricted as detailed in Note 3.

Based on the rights to cost recovery and revenue established by the settlement agreement with the CPUC and CPUC implementing orders, including the PROACT resolution, SCE repaid its undisputed past-due obligations on March 1, 2002, with lump-sum payments to creditors from the proceeds of $1.6 billion in senior secured credit facilities, the remarketing of $196 million in pollution control bonds which were repurchased in late 2000, and existing cash on hand. The $1.6 billion senior secured credit facilities consist of a $300 million, two-year revolving credit loan, a $600 million, one-year loan and a $700 million, three-year loan. See Note 5.

The proceeds from the senior secured credit facilities and pollution control bond remarketing were used along with SCE's available cash to repay $3.2 billion in past-due obligations and $1.65 billion in near-term debt maturities. The past-due obligations consisted of: (1) $875 million to the PX; (2) $99 million to the ISO; (3) $1.1 billion to QFs; (4) $193 million in PX energy credits for energy service providers; (5) $531 million of matured commercial paper; (6) $400 million of principal on its 5-7/8% and 6-1/2% senior unsecured notes which were issued prior to the energy crisis; and (7) $23 million in preferred dividends in arrears. After making these payments, SCE has no material undisputed obligations that are past due or in default. The near-term debt maturities consisted of credit facilities whose maturity dates were extended several times and were scheduled to mature in March and May 2002. In addition, SCE has entered into an agreement with the CDWR to pay for prior deliveries of energy in installments of $100 million on April 1, 2002, $150 million on June 3, 2002, and the balance on July 1, 2002.

SCE's Board of Directors has not declared quarterly common stock dividends to SCE's parent, Edison International, since September 2000. Payment of dividends on SCE's common stock is restricted by the settlement agreement between the CPUC and SCE as detailed in Note 3.

Note 3. Regulatory Matters

CPUC Litigation Settlement Agreement

In November 2000, SCE filed a lawsuit against the CPUC in federal district court, seeking a ruling that SCE is entitled to full recovery of its past electricity procurement costs in accordance with the tariffs filed with the FERC. By agreement of the parties, a stay of the lawsuit was issued in April 2001 while SCE sought implementation of legislative, regulatory and executive actions to resolve the California energy crisis and SCE's related financial and liquidity problems. In October 2001, the court entered a stipulated judgment approving an agreement between the CPUC and SCE to settle the pending lawsuit. On January 23, 2002, the CPUC adopted a resolution implementing the settlement agreement.

Key elements of the settlement agreement include the following items:

- Establishment of the PROACT as of September 1, 2001, with an opening balance equal to the amount of SCE's procurement-related liabilities as of August 31, 2001 (approximately $6.4 billion), less SCE's cash and cash equivalents as of that date (approximately $2.5 billion), and less $300 million.

- Beginning September 1, 2001, SCE will apply to the PROACT, on a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. Unrecovered obligations in the PROACT will accrue interest from September 1, 2001.

- Maintain current rates (including surcharges) in effect until December 31, 2003, subject to certain adjustments or, if earlier, until the date that SCE recovers the entire PROACT balance. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years. The parties project that existing retail electric rates, including surcharges and as adjusted to reflect certain costs, will likely result in SCE recovering substantially all of its unrecovered procurement-related obligations prior to the end of 2003.

- If the CPUC concludes that it is desirable to authorize a securitized financing of SCE's procurement-related obligations, the parties will work together to achieve the securitization. Proceeds of any securitization will be credited to the PROACT when they are actually received.

- During the period that SCE is recovering its previously incurred procurement-related obligations, no penalty will be imposed by the CPUC on SCE for any noncompliance with CPUC-mandated capital structure requirements.

- SCE can incur up to $250 million of recoverable costs to acquire financial instruments and engage in other transactions intended to hedge fuel cost risks associated with SCE's retained generation assets and power purchase contracts with QFs and other utilities. As of December 31, 2001, SCE had purchased $209 million in hedging instruments.

- SCE will not declare or pay dividends or other distributions on its common stock (all of which is held by its parent) prior to the earlier of the date SCE has recovered all of its procurement-related obligations in the PROACT or January 1, 2005. However, if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends, and the CPUC will not unreasonably withhold its consent.

- To ensure the ability of SCE to continue to provide adequate service, SCE may make capital expenditures above the level contained in current rates, up to $900 million per year, which will be treated as recoverable costs.

- Subject to certain qualifications, SCE will cooperate with the CPUC and the California Attorney General to pursue and resolve SCE's claims and rights against sellers of energy and related services, SCE's defenses to claims arising from any failure to make payments to the PX or ISO, and similar claims by the State of California or its agencies against the same adverse parties. During the recovery period discussed above, refunds obtained by SCE related to its procurement-related liabilities will be applied to the balance in the PROACT.

The settlement agreement states that one of its purposes is to restore the investment grade creditworthiness of SCE as rapidly as reasonably practicable so that it will be able to provide reliable electrical service as a state-regulated entity as it has in the past. SCE cannot provide assurance that it will regain investment grade credit ratings by any particular date.

On November 28, 2001, a federal court of appeals denied a California consumer group's request for a long-term stay of the settlement. The group had alleged that it was denied due process and that the CPUC had no authority to agree with SCE to violate the statutory rate freeze. In its ruling, the federal court of appeals also granted SCE's request for an expedited hearing of the appeal of the settlement filed by the consumer group. On March 4, 2002, the court of appeals heard argument on the appeal and the matter is now under submission. A decision could be issued anytime during the next several months. SCE cannot predict the outcome of the appeal or the impact that any outcome would have upon the stipulated judgment or settlement. Possible outcomes include affirmance, a return to the district court or reversal of the stipulated judgment. SCE cannot predict whether or how a ruling on the stipulated judgment could also affect the settlement agreement.

CDWR Power Purchases

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR and through the ISO are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, Assembly Bill 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue bonds to finance electricity purchases.

On March 27, 2001, the CPUC issued an interim order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢ per kWh surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which increased to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢ surcharge discussed in Rate Stabilization Proceedings), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late.

On February 21, 2002, the CPUC issued a decision implementing a CDWR revenue requirement of $9.0 billion to pay its bonds' costs and energy procurement costs for the period January 17, 2001, through December 31, 2002. The decision states that SCE's allocated share of this revenue requirement would be approximately $3.6 billion, and changes SCE's payment to 9.744¢ per kWh for all bills rendered on or after March 15, 2002. The decision requires SCE to pay the CDWR in equal monthly installments over a six-month period the difference in rates between January 17, 2001, and March 15, 2002. SCE estimates that this amount is approximately $41 million.

On February 28, 2002, SCE and the CDWR executed an agreement that resolves outstanding issues relating to the payment for electric power purchased for SCE's customers through the ISO real-time market (known as imbalance energy). Under this agreement, SCE will pay the CDWR for imbalance energy previously delivered in three installments ($100 million on April 1, 2002; $150 million on June 3, 2002; and the balance on July 1, 2002).

Rate Stabilization Proceedings

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the four-year rate freeze was to end on March 31, 2002, or earlier, depending on the pace of transition cost recovery. In December 2000, SCE filed an amended rate stabilization plan application, stating that the statutory rate freeze had ended in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001.

In January 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covered, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. In April 2001, the CPUC adopted an order instituting investigation that reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give first priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. The CPUC ordered testimony and briefing on these matters, which SCE filed in May and June 2001. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. On February 11, 2002, SCE filed an application for rehearing of the decision stating that the decision is an unlawful and erroneous attempt to rewrite the first priority condition rather than interpret it and that the decision could result in higher rates for SCE's customers. Neither Edison International nor SCE can predict what effects this investigation or any subsequent actions by the CPUC may have on either one of them.

In March 2001, the CPUC ordered a rate increase in the form of a 3¢ per kWh surcharge applied only to going-forward electric power procurement costs, effective immediately, and affirmed that a 1¢ interim surcharge granted in January 2001 is permanent. The 3¢ surcharge is to be added to the rate paid to the CDWR. Although the 3¢ increase was authorized as of March 27, 2001, the surcharge was not collected in rates until the CPUC established a rate design in early June 2001. To compensate for the two-month delay in collecting the 3¢ surcharge, the CPUC authorized an additional ½¢ surcharge for a 12-month period beginning in June 2001.

Utility-Retained Generation Proceeding

In June 2001, SCE filed a comprehensive proposal for new cost-of-service ratemaking for utility retained generation through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined in the general rate case. The URG proposal calls for balancing accounts for SCE-owned generation, QF and interutility contracts, procurement costs and ISO charges based on either actual or CPUC-authorized revenue requirements. Under the proposal, the four new balancing accounts would be effective January 1, 2001, for capital-related costs, and February 1, 2001, for non-capital-related costs. In addition, SCE's unamortized nuclear investment would be amortized and recovered in rates over a 10-year period, effective January 1, 2001. Should this application be approved as filed, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and regulatory assets related to purchased-power settlements and flow-through taxes, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance in accordance with the final URG decision.

On January 18, 2002, a CPUC administrative law judge issued a proposed decision and a CPUC commissioner issued an alternate proposed decision. Both the proposed and alternate proposed decisions adopt most of the elements of SCE's application, but propose eliminating an incentive pricing plan for San Onofre, effective January 1, 2002, and replacing it with balancing account treatment for San Onofre's operating costs, subject to a later reasonableness review. On February 7, 2002, another CPUC commissioner issued an alternate proposed decision recommending continuing the incentive pricing plan for San Onofre Units 2 and 3 through December 31, 2003, as originally provided in CPUC decisions adopted in early 1996. A final decision is expected in second quarter 2002.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. In December 2000, the FERC took limited action and failed to impose a price cap. SCE filed an emergency petition in the federal court of appeals challenging the FERC order and requesting the FERC to immediately establish cost-based wholesale rates. The court denied SCE's petition in January 2001.

In its December 2000 order, the FERC established an "underscheduling" penalty effective January 1, 2001, applicable to scheduling coordinators that do not schedule sufficient resources to supply 95% of their respective loads. In December 2001, the FERC eliminated the underscheduling penalty retroactive to January 1, 2001.

On April 25, 2001, after months of extremely high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region. The latest order is in effect until September 30, 2002.

After unsuccessful settlement negotiations among utilities, power sellers and state representatives, on July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges to the ISO and PX spot markets during the period from October 2, 2000, through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge will conduct evidentiary hearings on this matter. SCE cannot predict the amount of any potential refunds. Under the settlement of litigation with the CPUC, refunds will be applied to the balance in the PROACT.

Note 4. Derivative Instruments and Hedging Activities

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

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. The standard requires derivative instruments to be recognized on the balance sheet at fair value unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of the hedge. For a hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's equity under the caption "accumulated other comprehensive income," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately.

SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power-purchase contracts at fair value effective January 1, 2001. The realized loss of $26 million on the interest rate swap will be amortized over a period ending in 2008. Due to downgrades in SCE's credit ratings and SCE's failure to pay its obligations to the PX, the PX suspended SCE's market trading privileges and sought to liquidate SCE's remaining block forward contracts. Before the PX could do so, on February 2, 2001, the state seized the contracts. On September 30, 2001, a federal appeals court ruled that the governor of California acted illegally when he seized the contracts held by SCE. In conjunction with its settlement agreement with the CPUC, SCE has agreed to release any claim for compensation against the state for these contracts. However, if the PX prevails in its claims against the state, SCE may receive some refunds.

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

In October and November 2001, SCE purchased $209 million of call options that mitigate its exposure to increases in natural gas prices. Amounts paid to QFs for energy are based on natural gas prices. The options cover various periods from 2002 through 2003, averaging 11 million MMBtus per month. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings.

Fair values of financial instruments were:

In millions	December 31,	**2001**	2000
Financial assets:			
Decommissioning trusts		**$ 2,275**	$ 2,505
Gas options		**91**	—
Financial liabilities:			
DOE decommissioning and decontamination fees		**25**	31
Interest rate swap		**—**	21
Short-term debt		**2,103**	1,339
Long-term debt		**4,659**	5,178
Preferred stock subject to mandatory redemption		**118**	157
Preferred stock to be redeemed within one year		**102**	—

The fair value of financial assets is based on quoted market prices.

Financial liabilities' fair values are based on: discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees; quoted market prices for the interest rate swap; and brokers' quotes for short-term debt, long-term debt and preferred stock. Due to their short maturities, amounts reported for cash equivalents approximate fair value.

Note 5. Long-Term Debt

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

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

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt.

Commercial paper intended to be refinanced for a period exceeding one year, for which SCE has the ability to refinance, and used to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt.

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 non-bypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these non-bypassable residential and small commercial customer rates which constitute the transition property purchased by SCE Funding LLC. The notes are secured by the transition property and are not secured 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. Due to SCE's credit downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Long-term debt consisted of:

In millions December 31,	**2001**	2000
First and refunding mortgage bonds:		
2002 – 2026 (5.625% to 7.25%)	**$ 1,175**	$ 1,175
Rate reduction notes:		
2002 – 2007 (6.22% to 6.42%)	**1,478**	1,724
Pollution-control bonds:		
2008 – 2040 (5.125% to 7.2% and variable)	**1,216**	1,216
Bonds repurchased	**(550)**	(420)
Funds held by trustees	**(20)**	(20)
Debentures and notes:		
2001 – 2029 (5.875% to 7.625% and variable)	**2,450**	2,450
Subordinated debentures:		
2044 (8.375%)	**100**	100
Commercial paper for nuclear fuel	**60**	79
Long-term debt due within one year	**(1,146)**	(646)
Unamortized debt discount – net	**(24)**	(27)
Total	**$ 4,739**	$ 5,631

Long-term debt maturities and sinking-fund requirements for the next five years are: 2002 – $1.1 billion; 2003 – $1.4 billion; 2004 – $371 million; 2005 – $246 million; and 2006 – $446 million.

As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, SCE suspended payments of certain obligations, including $400 million of maturing principal on its 5-7/8% and 6-1/2% senior unsecured notes. From June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. All interest in arrears will be paid on April 1, 2002.

On March 1, 2002, SCE closed on $1.6 billion in syndicated senior secured credit facilities providing for $600 million of one-year term loans, $700 million of three-year term loans, and $300 million of two-year revolving credit loans. The interest rate for the revolving credit loans and the one-year loan is a eurodollar rate plus 2.5% or a bank prime or equivalent rate plus 1.5%, at SCE's election. The interest rate for the three-year loans is a eurodollar rate plus 3% or a bank prime or equivalent rate plus a margin of 2%, at SCE's election. The credit facilities are secured by three newly issued series of SCE first mortgage bonds. The proceeds of the loans, along with available cash, were used to repay all of SCE's past due obligations and near-term maturities, which include the senior notes.

Note 6. Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks.

Short-term debt consisted of:

In millions December 31,	**2001**	2000
Commercial paper	**$ 531**	$ 700
Bank loans	**1,650**	835
Other	**6**	—
Amount reclassified as long-term debt	**(60)**	(79)
Unamortized discount	**—**	(5)
Total	**$ 2,127**	$ 1,451
Weighted average interest rates	**5.3%**	6.9%

As of January 2001, SCE had borrowed the entire $1.65 billion in funds available under its credit lines. The proceeds were used in part to repurchase pollution control bonds; the balance was retained as a liquidity reserve. SCE conserved cash by deferring payment of $531 million of matured commercial paper.

SCE repaid its credit line borrowings and commercial paper using proceeds from its March 1, 2002, financings. See further discussion in Note 2.

Note 7. Preferred Stock

Authorized shares of preferred and preference stocks are: $25 cumulative preferred – 24 million; $100 cumulative preferred – 12 million; and preference – 50 million. All cumulative preferred stocks are redeemable. Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 2002 – $105 million; 2003 – $9 million; 2004 – $9 million; 2005 – $9 million; and 2006 – $9 million.

Cumulative preferred stocks consisted of:

Dollars in millions, except per share amounts	December 31, 2001 Shares Outstanding	December 31, 2001 Redemption Price	**2001**	2000
Not subject to mandatory redemption:				
$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
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$ 100.00	**$ 75**	$ 75
6.45	1,000,000	100.00	**100**	100
7.23	807,000	100.00	**81**	81
Preferred stock to be redeemed within one year			**(105)**	—
Total			**$ 151**	$ 256

SCE did not issue or redeem any preferred stock in the last three years.

In 2001, SCE's Board did not declare the regular quarterly dividends for any of SCE's cumulative preferred stock. As of February 28, 2002, SCE's preferred stock dividends in arrears were $23 million. On March 11, 2002, SCE repaid its past due preferred stock dividends.

Note 8. 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 calculates its tax liability on a stand-alone basis.

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

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

In millions December 31,	2001	2000
Deferred tax assets:		
Decommissioning	**$ 99**	$ 98
Accrued charges	**472**	379
Investment tax credits	**72**	81
Property-related	**192**	277
Regulatory balancing accounts	**1,709**	1,763
Unbilled revenue	**(10)**	101
Unrealized gains or losses	**310**	420
Other	**145**	56
Total	**$ 2,989**	$ 3,175
Deferred tax liabilities:		
Property-related	**$ 2,248**	$ 2,184
Capitalized software costs	**224**	264
Regulatory balancing accounts	**2,929**	1,632
Unrealized gains and losses	**208**	317
Other	**312**	242
Total	**$ 5,921**	$ 4,639
Accumulated deferred income taxes – net	**$ 2,932**	$ 1,464
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$ 3,365**	$ 2,009
Included in current assets	**433**	545

The current and deferred components of income tax expense (benefit) were:

In millions Year ended December 31,	2001	2000	1999
Current:			
Federal	**$ 240**	$ (104)	$ 299
State	**29**	—	79
	269	(104)	378
Deferred – federal and state:			
Accrued charges	**(79)**	(133)	(76)
Investment and energy tax credits – net	**(6)**	(41)	(45)
Property-related	**174**	(302)	(194)
Regulatory asset amortization	**(138)**	251	7
Regulatory balancing accounts	**1,345**	(740)	371
State tax – privilege year	**(36)**	31	7
Unbilled revenue	**101**	20	(5)
Other	**28**	(4)	(5)
	1,389	(918)	60
Total	**$ 1,658**	$ (1,022)	$ 438

The composite federal and state statutory income tax rate was 40.551% for all years presented.

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

Year ended December 31,	**2001**	2000	1999
Federal statutory rate	**35.0%**	35.0%	35.0%
Capitalized software	**—**	—	(2.4)
Investment and energy tax credits	**(0.1)**	1.4	(4.4)
Property-related and other	**0.1**	(6.6)	9.3
State tax – net of federal deduction	**5.8**	3.7	8.5
Effective tax rate	**40.8%**	33.5%	46.0%

Note 9. Employee Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined-contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $29 million in 2001, $29 million in 2000 and $25 million in 1999.

Pension Plan

SCE has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. SCE recognizes pension expense as calculated by the actuarial method used for ratemaking. In April 1999, SCE adopted a cash balance feature for its pension plan.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2001**	2000
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,200**	$ 2,075
Service cost	**67**	63
Interest cost	**154**	155
Actuarial loss (gain)	**88**	90
Benefits paid	**(182)**	(183)
Benefit obligation at end of year	**$ 2,327**	$ 2,200
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 3,067**	$ 3,078
Actual return on plan assets	**(162)**	143
Employer contributions	**—**	29
Benefits paid	**(182)**	(183)
Fair value of plan assets at end of year	**$ 2,723**	$ 3,067
Funded status	**$ 396**	$ 867
Unrecognized net loss (gain)	**(234)**	(745)
Unrecognized transition obligation	**17**	22
Unrecognized prior service cost	**109**	118
Recorded asset	**$ 288**	$ 262
Discount rate	**7.0%**	7.25%
Rate of compensation increase	**5.0%**	5.0%
Expected return on plan assets	**8.5%**	8.5%

Expense components were:

In millions Year ended December 31,	2001	2000	1999
Service cost	**$ 67**	$ 63	$ 66
Interest cost	**154**	155	146
Expected return on plan assets	**(251)**	(266)	(188)
Special termination benefits	**13**	—	—
Net amortization and deferral	**(9)**	(40)	12
Expense under accounting standards	**(26)**	(88)	36
Regulatory adjustment – deferred	**39**	88	14
Total expense recognized	**$ 13**	$ —	$ 50

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.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2001	2000
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,762**	$ 1,462
Service cost	**44**	39
Interest cost	**129**	121
Actuarial loss (gain)	**61**	202
Benefits paid	**(71)**	(62)
Benefit obligation at end of year	**$ 1,925**	$ 1,762
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,200**	$ 1,283
Actual return on plan assets	**(92)**	(40)
Employer contributions	**102**	19
Benefits paid	**(71)**	(62)
Fair value of plan assets at end of year	**$ 1,139**	$ 1,200
Funded status	**$ (786)**	$ (562)
Unrecognized net loss (gain)	**390**	141
Unrecognized transition obligation	**295**	323
Recorded asset (liability)	**$ (101)**	$ (98)
Discount rate	**7.25%**	7.5%
Expected return on plan assets	**8.2%**	8.2%

Expense components were:

In millions Year ended December 31,	2001	2000	1999
Service cost	**$ 44**	$ 39	$ 46
Interest cost	**129**	121	109
Expected return on plan assets	**(98)**	(106)	(79)
Special termination benefits	**2**	—	—
Net amortization and deferral	**27**	27	27
Total expense	**$ 104**	$ 81	$ 103

The assumed rate of future increases in the per-capita cost of health care benefits is 10.5% for 2002, gradually decreasing to 5.0% for 2008 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2001, by $300 million and annual aggregate service and interest costs by $33 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2001, by $243 million and annual aggregate service and interest costs by $26 million.

Stock Options and Other Equity-Based Awards

In 1998, Edison International shareholders approved the Edison International equity compensation plan, replacing the long-term incentive compensation program that had been adopted by Edison International shareholders in 1992. The 1998 plan authorizes a limited annual award of Edison International common shares and options on shares. The annual authorization is cumulative, allowing subsequent issuance of previously unutilized awards. In May 2000, the Edison International Board of Directors adopted an additional plan, the 2000 equity plan, under which the special options discussed below were awarded.

Under the 1992, 1998 and 2000 plans, options on 4.9 million shares of Edison International common stock are currently outstanding to officers and senior managers.

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

Edison International stock options awarded prior to 2000 include a dividend equivalent feature. Dividend equivalents on stock options issued after 1993 and prior to 2000 are accrued to the extent dividends are declared on Edison International common stock, and are subject to reduction unless certain performance criteria are met. Only a portion of 1999 Edison International stock option awards include a dividend equivalent feature.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, but vesting does not begin until May 2002. Earlier options had a three-year vesting period with one-third of the total award vesting annually. If an option holder retires, dies, is terminated by the company, or is terminated while permanently and totally disabled (qualifying event) during the vesting period, the unvested options will vest on a pro rata basis.

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

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

December 31,	**2001**	2000
Expected life	**7 years – 10 years**	7 years – 10 years
Risk-free interest rate	**4.7% – 6.1%**	4.7% – 6.0%
Expected volatility	**17% – 52%**	17% – 46%

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

The weighted-average fair value of options granted during 2001 and 2000 was $4.53 per share option and $5.50 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 2001, and December 31, 2000, was 6 years and 7 years, respectively.

For the years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. The 2000 performance shares were restructured as retention incentives in December 2000, which pay as a combination of Edison International common stock and cash if the executive remains employed at the end of the performance period. The performance period ended December 31, 2001, for half of the award, and ends on December 31, 2002, for the remainder. Additional performance shares were awarded in January 2001 and January 2002. The 2001 performance shares vest December 31, 2003, half in shares of Edison International common stock and half in cash. The 2002 performance shares vest December 31, 2004, also half in shares of common stock and half in cash. The number of shares that will be paid out from the 2002 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specified group of peer companies.

The 2000 and 2001 performance shares and deferred stock unit values are accrued ratably over a three-year performance period. The 2002 performance shares will be valued based on Edison International's stock performance relative to the stock performance of other such entities.

In March 2001, deferred stock units were awarded as part of a retention program. These vest and will be paid between March 12, 2002, and March 12, 2003, depending on performance. The deferred stock units are payable on the vesting date in shares of Edison International common stock.

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units. The exchange ratio was based on the Black-Scholes value of the options and the stock price at the time the offer was extended. The exchange took place in November 2001; the options that participants elected to exchange were cancelled, and deferred stock units were issued. Approximately three options were cancelled for each deferred stock unit issued. The deferred stock units will vest 25% per year over four years, with the first vesting date in November 2002. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life: 8 – 9 years; risk-free interest rate: 5.10%; expected volatility: 52%.

SCE measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation program was $1 million in 2001, $4 million in 2000 and $5 million in 1999.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma net income (loss) available for common stock of $2.383 billion for 2001, $(2.054) billion for 2000 and $484 million for 1999.

Note 10. Jointly Owned Utility Projects

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

The investment in each project as of December 31, 2001, was:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 41	$ 11	60%
Pacific Intertie	240	84	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	469	365	48
Mohave (coal)	334	246	56
Palo Verde (nuclear)[1]	1,653	1,648	16
San Onofre (nuclear)[1]	4,305	4,283	75
Total	$ 7,042	$ 6,637	

(1) Regulatory assets, which were written off as a charge to earnings as of December 31, 2000, as discussed in Note 1.

Note 11. Commitments

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates. Operating lease expense was $19 million in 2001, $20 million in 2000 and $17 million in 1999.

Estimated remaining commitments for noncancelable leases at December 31, 2001, were:

Year ended December 31,	In millions
2002	$ 14
2003	13
2004	11
2005	8
2006	6
Thereafter	13
Total	$ 65

Nuclear Decommissioning

Decommissioning is estimated to cost $2.1 billion in current-year dollars, based on site-specific studies performed in 1998 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 $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current dollar decommissioning costs, escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which effective June 1999 receive contributions of approximately $25 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.9% to 4.9%.

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 2026 and 2028 for the Palo Verde units. Decommissioning costs, which are recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre's Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

Decommissioning expense was $96 million in 2001, $106 million in 2000 and $124 million in 1999. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.5 billion at December 31, 2001, and $1.4 billion at December 31, 2000. The estimated cost to decommission San Onofre Unit 1 is recorded as a liability.

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

Trust investments (cost basis) include:

In millions	Maturity Dates	December 31,	**2001**	2000
Municipal bonds	2001 – 2034		**$ 463**	$ 548
Stocks	–		**637**	531
U.S. government issues	2001 – 2029		**332**	421
Short-term and other	2001		**334**	220
Total			**$ 1,766**	$ 1,720

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $13 million in 2001, $38 million in 2000 and $58 million in 1999. Proceeds from sales of securities (which are reinvested) were $3.9 billion in 2001, $4.7 billion in 2000 and $2.6 billion in 1999. Approximately 91% of the trust fund contributions were tax-deductible.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. Certain SCE gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered.

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the balance sheets.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $158 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power purchase contracts (approximately $31 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2002 through 2006 are estimated below:

In millions	2002	2003	2004	2005	2006
Fuel supply contract payments	$ 168	$ 108	$ 103	$ 106	$ 109
Purchased-power capacity payments	629	629	626	624	572

Note 12. 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.

Energy Crisis Issues

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit involves securities fraud claims arising from alleged improper accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock between July 21, 2000, and April 17, 2001. This lawsuit has been consolidated with another similar lawsuit filed on March 15, 2001. A consolidated class action complaint was filed on August 3, 2001. On September 17, 2001, SCE and Edison International filed a motion to dismiss for failure to state a claim. On March 8, 2002, the district court issued an order dismissing the complaint with prejudice. The plaintiffs could appeal this ruling to the court of appeals.

SCE has been a defendant in a number of legal actions brought by various QFs arising out of SCE's suspension of payments for electricity delivered by the QFs during the period November 1, 2000, through March 26, 2001. The QF claims were eventually largely subsumed within agreements with the litigating QFs providing for a provisional settlement of the parties' disputes. On March 1, 2002, SCE paid the amounts due under settlement agreements with these QFs, which triggered the releases and other provisions of the settlements. As a result, the litigation with those QFs to whom payment in full has been made under the parties' settlement agreements should be dismissed during 2002. However, SCE's March 1, 2002, payments excluded several QFs or did not result in immediate releases under the settlement agreements based on unique disputes or other unique circumstances, including the status of regulatory approval.

Environmental Protection

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 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 42 identified sites is $111 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $279 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $50 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. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $76 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 now 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 $10 million to $25 million. Recorded costs for 2001 were $18 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 and, based upon the CPUC's regulatory treatment of environmental-cleanup 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.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 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 U.S. 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 $88 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 $175 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.

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. These policies are issued by a mutual insurance company owned by utilities with nuclear facilities. 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 $35 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and development of a facility for disposal of spent nuclear fuel and high-level radioactive waste. Such a facility was to be in operation by January 1998. However, the DOE did not meet its obligation. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or from other nuclear power plants. Extended delays by the DOE could lead to consideration of costly alternatives involving 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 one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

SCE, as operating agent, has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. SCE plans to spend approximately $34 million for the initial interim spent fuel storage at San Onofre Units 2 and 3 through 2008.

Palo Verde on-site spent fuel storage capacity will accommodate needs until 2003 for Unit 2, and until 2004 for Units 1 and 3. Arizona Public Service Company, operating agent for Palo Verde, is constructing an interim fuel storage facility that is expected to be completed in 2002.

Quarterly Financial Data

	2001					2000				
In millions	**Total**	**Fourth**	**Third**	**Second**	**First**	**Total**	**Fourth**	**Third**	**Second**	**First**
Operating revenue	$8,126	$2,296	$2,726	$1,592	$1,512	$7,870	$1,755	$2,432	$1,853	$1,830
Operating income (loss)	4,617	3,956	1,294	204	(837)	(2,659)	(3,840)	447	385	349
Net income (loss)	2,408	2,310	657	34	(593)	(2,028)	(2,485)	177	161	119
Net income (loss) available for common stock	2,386	2,304	652	28	(598)	(2,050)	(2,491)	172	156	113
Common dividends declared	—	—	—	—	—	279	—	92	91	96

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

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

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

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

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

Thomas M. Noonan
Vice President
and Controller

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

March 25, 2002

To Southern California Edison Company:

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

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

ARTHUR ANDERSEN LLP

Los Angeles, California
March 25, 2002

Board of Directors

Southern California Edison Company

Warren Christopher*
Senior Partner,
O'Melveny & Myers (law firm),
Los Angeles, California

Alan J. Fohrer
Chairman of the Board and
Chief Executive Officer,
Southern California Edison Company

Joan C. Hanley
The Former General Partner and
Manager,
Miramonte Vineyards,
Rancho Palos Verdes, California

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General Partner,
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Chief Executive Officer
Pacific Life Insurance Company,
Newport Beach, California

Daniel M. Tellep
Retired Chairman of the Board,
Lockheed Martin Corporation
(aerospace industry),
Bethesda, Maryland

* Retiring on May 14, 2002.

Management Team

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Chairman of the Board and
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President,
Generation Business Unit

Pamela A. Bass
Senior Vice President,
Customer Service Business Unit

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
Business Unit

Mahvash Yazdi
Senior Vice President and
Chief Information Officer

Emiko Banfield
Vice President, Shared Services

Robert C. Boada
Vice President and Treasurer

Clarence Brown
Vice President,
Corporate Communications

Bruce C. Foster
Vice President, San Francisco
Regulatory Operations

A. L. Grant
Vice President, Engineering and
Technical Services

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

Lawrence D. Hamlin
Vice President, Power Production

Harry B. Hutchison
Vice President, Mass Customers

James A. Kelly
Vice President,
Regulatory Compliance

Russell W. Krieger
Vice President,
Nuclear Generation

Thomas M. Noonan
Vice President and Controller

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

Pedro J. Pizarro
Vice President,
Business Development

Frank J. Quevedo
Vice President, Equal Opportunity

W. James Scilacci
Vice President and
Chief Financial Officer

Dale E. Shull, Jr.
Vice President, Power Delivery

Anthony L. Smith
Vice President, Tax

Joseph J. Wambold
Vice President, Nuclear Business
and Support Services

Beverly P. Ryder
Secretary

Shareholder Information

Annual Meeting of Shareholders

Tuesday, May 14, 2002
10:00 a.m.
DoubleTree Hotel Ontario
222 N. Vineyard Avenue
Ontario, California 91764

Stock Listing and Trading Information

SCE Preferred Stock

SCE's preferred stocks are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05%, 6.45% and 7.23% series are not listed.

Where to Buy and Sell Stock

The listed preferred stocks may be purchased through any brokerage firm. Firms handling unlisted series can be located through your broker.

Transfer Agent and Registrar

Wells Fargo Bank Minnesota, N.A. maintains shareholder records and is the transfer agent and registrar for SCE preferred stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7:00 a.m. and 7:00 p.m. (Central Time), Monday through Friday, regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 forms 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.

The address of Wells Fargo Shareowner Services is:

161 North Concord Exchange Street
South St. Paul, MN 55075-1139
FAX: (651) 450-4033
E-mail: stocktransfer@wellsfargo.com

SCE Web Address:
www.edisoninvestor.com

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