



SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL*SM Company

1999 Annual Report

A Profile of Southern California Edison Company

Southern California Edison (SCE) is the nation's second largest investor-owned electric utility. Headquartered in Rosemead, California, SCE is a subsidiary of Edison International, which is primarily an energy-services company.

SCE, a 114-year-old electric utility, serves 4.3 million customers and more than 11 million people within a 50,000-square-mile area of central, coastal and Southern California.

Contents

1	Management's Discussion and Analysis of Results of Operations and Financial Condition
11	Consolidated Financial Statements
16	Notes to Consolidated Financial Statements
33	Quarterly Financial Data
34	Responsibility for Financial Reporting
35	Report of Independent Public Accountants
36	Selected Financial and Operating Data: 1995-1999
37	Board of Directors
37	Management Team

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

Results of Operations

Earnings

Southern California Edison Company's (SCE) 1999 earnings were \$484 million, compared with \$490 million in 1998 and \$576 million in 1997. SCE's 1999 earnings include an approximately \$15 million one-time tax benefit due to an Internal Revenue Service ruling. Excluding the one-time tax benefit, SCE's 1999 earnings were \$469 million, down \$21 million from 1998. The 1999 decrease was primarily due to the accelerated depreciation of SCE's generation assets, partially offset by higher kilowatt-hour sales in 1999. The \$86 million earnings decrease in 1998 was largely due to lower authorized revenue, which resulted from reduced authorized returns on generating assets and a lower earning asset base resulting from the accelerated recovery of investments and divestiture of 12 gas- and oil-fueled generating plants, partially offset by superior operating performance at San Onofre Nuclear Generating Station.

Operating Revenue

As a result of industry restructuring, customers have an option to buy power from SCE or directly from the California Power Exchange (PX), thus becoming direct access customers. Most direct access customers are continuing to be billed by SCE, but are also given a credit for the generation portion of their bills. Operating revenue increased by less than 1% in 1999, as increased kilowatt-hour sales and revenue resulting from maintenance work SCE is providing the new owners of the divested plants was almost completely offset by the credit given to customers who chose direct access. Operating revenue decreased 6% in 1998 compared to 1997, reflecting lower average residential rates, partially offset by an increase in revenue resulting from the maintenance work noted above. In 1999, over 93% of operating revenue was from retail sales. Retail rates are regulated by the California Public Utilities Commission (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.

Legislation enacted in September 1996 provided for, among other things, a 10% rate reduction for residential and small commercial customers beginning in 1998 and other rates to remain frozen at June 1996 levels (system average of 10.1¢ per kilowatt-hour). See discussion of proposed post-rate freeze rates in Regulatory Environment.

The changes in operating revenue resulted from:

<i>In millions</i>	Year ended December 31,	1999	1998	1997
Operating revenue —				
Rate changes (including refunds)		\$ (65)	\$ (498)	\$ 173
Direct access credit		(213)	(29)	—
Sales volume changes		191	(44)	193
Other		110	117	4
Total		\$ 23	\$ (454)	\$ 370

Operating Expenses

Fuel expense decreased in both 1999 and 1998. The decreases were the result of the sale of the 12 generating plants in the first half of 1998.

Purchased-power expense — contracts decreased in both 1999 and 1998, primarily due to SCE entering into settlements to end its contractual obligations with certain nonutility generators (known as qualifying facilities, or QFs) and the terms in some of the QF contracts reverting to a lower price basis. Prior to April 1998, SCE was required under federal law and CPUC orders 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. In 1999, SCE paid about \$1.5 billion (including energy and capacity payments) more for these power purchases than the cost of power available from other

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

sources. SCE is continuing to purchase power under existing contracts from certain QFs and from other utilities.

Since April 1, 1998, SCE has been required to sell all of its generated power through the PX and acquire all of its power from the PX to distribute to its retail customers. These transactions with the PX are reported net. In 1999, PX purchased-power expense increased 19%, mainly due to three additional months of PX transactions in 1999. However, when 1999 PX purchased-power expense is compared on the same nine-month basis as 1998, the increase is less than 1%, despite the fact SCE experienced a significant decrease in the volume of kilowatt-hour sales through the PX. The lower volume of sales through the PX in 1999 was the result of less generation at SCE (San Onofre refueling outages in 1999, divestiture of 12 generating plants in 1998 and reduced hydroelectric generation) and fewer purchases from QFs. QF power purchases and other purchased power is also sold through the PX.

Provisions for regulatory adjustment clauses decreased in both 1999 and 1998. The 1999 decrease was mainly due to undercollections related to the difference between generation-related revenue and generation-related costs and the rate-making treatment of the rate reduction notes. These undercollections were partially offset by overcollections related to the administration of public purpose funds. The 1998 decrease was mainly due to the revenue deferrals related to the rate-making treatment of the rate reduction notes. This rate-making treatment has allowed for the deferral of the recovery of a portion of the transition-related costs, from a four-year period to a 10-year period. See the discussion in Revenue and Cost-Recovery Mechanisms.

Other operating expenses increased in both 1999 and 1998, primarily due to an increase in mandated transmission service (known as must-run reliability services) expense and PX and Independent System Operator (ISO) costs incurred by SCE. In 1998, storm damage expense resulting from the harsh winter and direct access activities also contributed to the increase.

Maintenance expense decreased in 1999, primarily due to lower expenses incurred at distribution facilities.

Depreciation, decommissioning and amortization expense remained constant in 1999. In 1998, depreciation, decommissioning and amortization expense increased, primarily due to the further acceleration of recovery of San Onofre Units 2 and 3 and the Palo Verde Nuclear Generating Station units, accelerated recovery of the generating plants, and the amortization of the loss on plant sales. The amortization of the loss on plant sales, as well as the accelerated recoveries implemented in 1998 are part of the competition transition charge (CTC) mechanism.

In 1998, income tax expense decreased due to lower pre-tax income, as well as additional amortization related to the CTC mechanism.

Net gain on sale of utility plant resulted from the sale of SCE's generating plants in 1998. Gains were used to reduce stranded costs. Losses will be recovered from customers over the transition period through the CTC mechanism.

Other Income

Interest and dividend income increased in 1998, reflecting higher investment balances due to the sale of the generating plants, as well as increases in interest earned on higher balancing account undercollections.

Other nonoperating income increased in 1999, when compared to 1998, primarily due to the one-time adjustment in 1999, resulting from an Internal Revenue Service ruling that allowed SCE to record a tax benefit, and the gain on sales of equity investments. Other nonoperating income increased substantially in 1998 mostly due to the additional accruals in 1997 for regulatory matters.

Interest Expense

Interest and amortization on long-term debt increased in 1998, when compared to 1997, mainly due to the issuance of the rate reduction notes in December 1997. Interest on the rate reduction notes was \$134 million in 1999 and \$148 million in 1998.

Other interest expense increased in 1999, mostly due to higher overall short-term debt balances necessary to meet general cash requirements during the year, as well as higher interest expense related to balancing account overcollections. In 1998, other interest expense decreased substantially, mostly due to lower overall short-term debt balances, particularly short-term debt used to finance fuel inventories. These fuel inventories are no longer needed because of the divestiture of the generating plants in the first half of 1998.

Financial Condition

SCE's liquidity is primarily affected by debt maturities, dividend payments and capital expenditures. Capital resources include cash from operations and external financings.

Edison International's board of directors has authorized the repurchase of up to \$2.8 billion of its outstanding shares of common stock. Edison International repurchased approximately 101 million shares (\$2.4 billion) between January 1995 and February 1999, funded by dividends from its subsidiaries and the proceeds of the rate reduction notes.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled \$1.5 billion in 1999, \$1.0 billion in 1998 and \$1.7 billion in 1997. Cash from operations exceeds capital requirements for all years presented. SCE's cash flow coverage of dividends was 2.2 times for 1999, and 0.9 times for both 1998 and 1997. The 1999 increase primarily reflects the rate-making treatment of the gains on sales of the generating plants, as well as the special dividends SCE paid to Edison International (\$680 million in 1998 and \$1.2 billion in 1997).

Cash Flows from Financing Activities

At December 31, 1999, SCE had total credit lines of \$1.25 billion, with \$39 million available for general purpose, short-term debt and \$515 million available for the long-term refinancing of its variable-rate pollution-control bonds. These unsecured lines of credit are at negotiated or bank index rates and expire in 2002.

Short-term debt is used to finance fuel inventories and general cash requirements. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors, including limitations imposed by SCE's articles of incorporation and trust indenture. As of December 31, 1999, SCE could issue approximately \$11.1 billion of additional first and refunding mortgage bonds and \$2.8 billion of preferred stock at current interest and dividend rates.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1999, SCE had the capacity to pay \$433 million in additional dividends and continue to maintain its authorized capital structure.

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

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

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 2000 and ending in 2007, with interest rates ranging from 6.14% 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 generally accepted accounting principles, 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.

On January 24, 2000, SCE issued \$250 million of 7-5/8% notes, due 2010.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant, proceeds from the sale of plant and funding of nuclear decommissioning trusts. Decommissioning costs are accrued and recovered in rates over the term of each nuclear generating facility's operating license. 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 (\$2.0 billion), 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 receive SCE contributions of approximately \$25 million per year.

Market Risk Exposures

SCE's primary market risk exposures arise from fluctuations in energy prices and interest rates. 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.

A 10% increase in market interest rates would result in a \$7 million increase in the fair value of SCE's interest rate hedge agreement. A 10% decrease in market interest rates would result in a \$7 million decline in the fair market value of SCE's interest rate hedge agreement. A 10% increase in natural gas prices would result in a \$20 million increase in the fair market value of gas call options. A 10% decrease in natural gas prices would result in an \$11 million decline in the fair market value of gas call options. A 10% change in market rates is expected to have an immaterial effect on SCE's other financial instruments.

As a result of the rate freeze established in the restructuring legislation, SCE's transition costs are recovered as the residual component of rates once the costs for distribution, transmission, public purpose programs, nuclear decommissioning and the cost of supplying power to its customers through the PX and ISO have already been recovered. Accordingly, more revenue will be available to cover transition costs when market prices in the PX and ISO are low than when PX and ISO prices are high. The PX and ISO market prices to date have generally been consistent, although some irregular price spikes have occurred. The ISO has responded to price spikes in the market for reliability services (referred to as ancillary services) by imposing a price cap on the market for such services until certain actions have been completed to improve the functioning of those markets. Similarly, the ISO currently maintains a cap on its market for imbalance energy until adequate measures to improve the efficient operation of the market have been implemented. The caps in these markets mitigate the risk of costly price spikes that would reduce the revenue available to SCE to pay transition costs. The price cap instituted by the ISO in the

summer of 1998 was \$250/MWh. In October 1999, that cap was raised to \$750/MWh and will remain at that level through the summer of 2000, unless certain identified market improvements do not occur. Under such circumstances, the price cap can be reduced to \$500/MWh. SCE has entered into gas call options to mitigate high natural gas prices, since increases in natural gas prices tend to raise the price of electricity.

In July 1999, SCE began participating in forward purchases through a PX block forward market. In the PX block forward market, SCE can purchase monthly blocks of energy for six days a week (excluding Sundays and holidays) for 16 hours a day. These purchases can be made up to 12 months in advance of the delivery date. The CPUC has currently limited SCE's use of the PX block forward market to a maximum of approximately 2,000 MW in any month. The PX has requested authority from the FERC to sell other forward products including a peak product, six days a week, for eight hours a day. SCE has requested rate-making treatment from the CPUC for its use of these additional products, and has requested an expansion of the limits from all forward PX products up to 5,200 MW in summer months. SCE requested permission from the CPUC to begin a demand responsiveness program that would allow customers to be paid to curtail their load during times of very high prices. SCE expects a CPUC resolution on these issues by the end of March 2000.

Projected Capital Requirements

SCE's projected construction expenditures for the next five years are: 2000 — \$1.1 billion; 2001 — \$1.0 billion; 2002 — \$908 million; 2003 — \$901 million; and 2004 — \$890 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 2000 — \$571 million; 2001 — \$646 million; 2002 — \$446 million; 2003 — \$371 million; and 2004 — \$371 million.

Preferred stock redemption requirements for the next five years are: 2000 and 2001 — zero; 2002 — \$105 million; 2003 — \$9 million; and 2004 — \$9 million.

Regulatory Environment

SCE currently operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing as a result of a 1995 CPUC decision on restructuring and state legislation enacted in 1996. The Statute substantially adopted the CPUC's restructuring decision by addressing stranded-cost recovery for utilities and providing a certain cost-recovery time period for the transition costs associated with generation-related assets. The Statute also 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. The Statute mandated other rates to remain frozen at June 1996 levels (system average of 10.1¢ per kilowatt-hour), including those for large commercial and industrial customers, and included provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement during the 1998—2001 transition period. In addition, the Statute mandated the implementation of the CTC (see the detailed discussion in Revenue and Cost-Recovery Mechanisms) that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring.

Revenue and Cost-Recovery Mechanisms

Revenue is determined by various mechanisms depending on the utility operation. Revenue related to distribution operations is being determined through a performance-based rate-making (PBR) mechanism and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return. The distribution PBR will extend through December 2001. 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

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

changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a 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. Transmission revenue is being determined through FERC-authorized rates that are subject to refund.

SCE's transition costs are being recovered through a non-bypassable CTC. This charge applies to all customers who were using or began using utility services on or after the CPUC's December 1995 restructuring decision date. At the beginning of the transition period, SCE estimated its transition costs to be approximately \$10.6 billion (1998 net present value) from 1998 through 2030. This estimate was based on incurred costs, forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. Transition costs related to power-purchase contracts are being recovered through the terms of their contracts while most of the remaining transition costs will be recovered through 2001. The potential transition costs are comprised of \$6.4 billion from SCE's QF contracts, which are the direct result of prior legislative and regulatory mandates, and \$4.2 billion from costs pertaining to certain generating assets (including the 1998 sale of SCE's generating plants) and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs. During 1998, SCE sold all of its gas- and oil-fueled generation plants for \$1.2 billion, over \$500 million more than the combined book value. Net proceeds of the sales were used to reduce stranded costs, which otherwise were expected to be collected through the CTC mechanism. If events occur during the restructuring process that result in all or a portion of the transition costs being improbable of recovery, SCE could have write-offs associated with these costs if they are not recovered through another regulatory mechanism.

Revenue from generation-related operations is being determined through the competitive market and the CTC mechanism, which now includes the nuclear rate-making agreements. The portion of revenue related to fossil and hydroelectric generation operations that is made uneconomic by electric industry restructuring is recovered through the CTC mechanism. The portion that is economic is recovered through the market. SCE's costs associated with its hydroelectric plants are being recovered through a performance-based mechanism. The mechanism sets the hydroelectric revenue requirement and establishes a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurs first. The mechanism provides that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement be credited against the costs to transition to a competitive market. In 1999, fossil and hydroelectric generation assets had the opportunity to earn a 7.22% return. SCE has filed an application with the CPUC regarding the market valuation of its hydroelectric facilities. See further discussion below.

SCE is recovering its investment in its nuclear facilities on an accelerated basis in exchange for a lower authorized rate of return. SCE's nuclear assets are earning an annual rate of return of 7.35%. In addition, the San Onofre plan authorizes a fixed rate of approximately 4¢ per kilowatt-hour generated for operating costs including incremental capital costs, and nuclear fuel and nuclear fuel financing costs. The San Onofre plan commenced in April 1996, and ends in December 2001 for the accelerated recovery portion, and in December 2003 for the incentive-pricing portion. Palo Verde's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, are subject to balancing account treatment. The Palo Verde plan commenced in January 1997 and ends in December 2001. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the CTC mechanism.

In March 1997, SCE filed its first FERC transmission rate case. In March 1999, a proposed FERC decision was issued which recommended a reduced rate of return on equity of 9.68% (compared to SCE's current CPUC rate for distribution of 11.6%) and a reduced return on transmission assets of 8.41% (compared to the current rate of 9.43% being earned on transmission assets). SCE filed comments

opposing the proposed decision in May 1999. In response to a recent FERC ruling, on November 1, 1999, SCE filed additional evidence regarding return on equity. A final FERC decision is expected during first quarter 2000. SCE does not expect the final decision to have a material effect on its results of operations or financial position.

As a further requirement of the law that restructured California's electric utility industry, in October 1999, SCE filed an application with the CPUC to approve an auction process for its 56% interest in the Mohave Generating Station. A CPUC decision on the auction process is expected in early 2000.

In order to comply with the restructuring legislation, on December 15, 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately \$1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based and revenue-sharing mechanism. The application had broad-based support from labor, ratepayer and environmental groups. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-index operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfalls from ratepayers. A final CPUC decision is expected by the end of 2000.

On January 7, 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the current rate freeze ends on March 31, 2002, or earlier, depending on the pace of CTC recovery. The proposal seeks CPUC approval of a rate redesign that will result in reduced rates for most customers when SCE completes the first phase of recovery of its transition costs. The proposed new rates are expected to reduce SCE's system average rates by about 17% from current frozen rate levels, based on certain assumptions about competitive energy prices. In addition, SCE's filing proposes to redesign and establish separate transmission and distribution rates to better reflect the actual costs to deliver electricity and serve customers. This pricing approach is consistent with CPUC policies requiring California's major utilities to move toward cost-based transmission and distribution rates.

Restructuring Implementation Costs

In May 1998, SCE filed an application with the CPUC to identify the categories of restructuring implementation costs (including costs related to the start-up and development of both the PX and ISO, and related to the implementation of direct access) and to establish the reasonableness of those costs incurred in 1997. In September 1999, the CPUC approved a settlement agreement between SCE, the CPUC's Office of Ratepayer Advocates and several other parties allowing SCE to recover substantially all (approximately \$300 million) of its restructuring implementation costs (incurred and estimated) for the period 1997-2001. In addition, the settlement provides that up to \$210 million of generation-related costs (transition costs) that are displaced by recovery of the restructuring implementation costs during the rate freeze may be recovered after December 31, 2001, the date SCE would cease to recover these transition costs under restructuring legislation.

Accounting for Generation-Related Assets

If the CPUC's electric industry restructuring plan continues as described above, SCE will be allowed to recover its transition costs through non-bypassable charges to its distribution customers (although its investment in certain generation assets is subject to a lower authorized rate of return). In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its generation assets based on new accounting guidance. The new guidance did not require SCE to write off any of its generation-related assets, including related regulatory assets. SCE has retained these assets on its balance sheet because the Statute and restructuring plan referred to above make probable their recovery through a non-bypassable charge to distribution customers. The regulatory assets relate primarily to the recovery of accelerated income tax benefits previously flowed through to customers, purchased power

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

contract termination payments and unamortized losses on reacquired debt. The new accounting guidance also permits the recording of new generation-related regulatory assets during the transition period that are probable of recovery through the CTC mechanism.

During the second quarter of 1998, additional guidance was developed related to the application of asset impairment standards to these assets. Using this guidance, SCE reduced its remaining nuclear plant investment by \$2.6 billion (as of June 30, 1998) and recording 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.

If during the transition period events were to occur that made the recovery of these generation-related regulatory assets no longer probable, SCE would be required to write off the remaining balance of such assets (approximately \$2.6 billion, after tax, at December 31, 1999) as a one-time, non-cash charge against earnings. At this time, SCE cannot predict what other revisions will ultimately be made during the restructuring process in subsequent proceedings or the effect, after the transition period, that competition will have on its results of operations or financial position.

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 11 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 45 identified sites is \$163 million. One of SCE's sites, a former pole-treating facility, is considered a federal Superfund site and represents 40% of its recorded liability. SCE believes that, due to the uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to \$284 million. In 1998, SCE sold all of its gas- and oil-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 42 of its sites, representing \$90 million of its recorded liability, through an incentive mechanism, which is discussed in Note 11. SCE has recorded a regulatory asset of \$126 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 \$5 million to \$15 million. Recorded costs for 1999 were \$14 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range 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 1990 Federal 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 issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. SCE filed comments on the proposed rulemaking in November 1999. In 1998, several environmental groups filed suit against the co-owners of the Mohave station regarding alleged violations of emissions limits. In order to accelerate resolution of key environmental issues regarding the plant, the parties filed, in concurrence with SCE and the other station owners, a consent decree, which was approved by the court in December 1999. The Environmental Protection Agency has notified SCE that the visibility concerns can be resolved by revising the Mohave station's Federal Implementation Plan to include the relevant provisions in the consent decree.

SCE's projected environmental capital expenditures are \$850 million for the 2000—2004 period, mainly for undergrounding certain transmission and distribution lines.

San Onofre Steam Generator Tubes

The San Onofre Units 2 and 3 steam generators have performed relatively well through the first 15 years of operation, with low rates of ongoing steam generator tube degradation. The steam generator design allows for the removal of up to 10% of the tubes before the rated capacity of the unit must be reduced. As a result of the increased degradation found during a 1997 inspection, a mid-cycle inspection outage was conducted in early 1998 for Unit 2. Continued degradation was found during this inspection. A favorable or decreasing trend in degradation was observed during inspection in the scheduled refueling outage in January 1999 and as a result, a mid-cycle inspection outage in early 2000 was unnecessary. With the results from the January 1999 outage, 7.5% of the tubes have now been removed from service.

During Unit 3's refueling outage, which was completed in May 1999, a complete inspection of the steam generator tubes was performed. Results obtained were within expectations. To date, 5.4% of Unit 3's tubes have been removed from service.

New Accounting Rules

In June 1998, a new accounting standard for derivative instruments and hedging activities was issued. The new standard, which as amended will be effective January 1, 2001, requires all derivatives to be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure would be reflected in other comprehensive income. Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE anticipates that most of its derivatives under the new standard would qualify for hedge accounting. SCE expects to recover in rates any market price changes from its derivatives that could potentially affect earnings. Accordingly, implementation of this new standard is not expected to affect earnings.

Year 2000 Issue

SCE implemented a comprehensive program to address potential Year 2000 computer system impacts, consisting of five phases: inventory, impact assessment, remediation, testing and implementation. SCE met its goal to have 100% of its critical systems Year 2000-ready by July 1, 1999. A critical system was defined as those applications and systems, including embedded processor technology, which if not appropriately remediated, may have had a significant impact on customers, the health and safety of the public and/or personnel, the revenue stream, or regulatory compliance. A system, application or physical

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

asset was deemed to be Year 2000-ready if it was determined by SCE to be suitable for continued use through 2028 (or through the last year of the anticipated life of the asset, whichever occurred first), even if not fully Year 2000-compliant (able to accurately process date/time data, between the 20th and 21st centuries, 1999 and 2000, and leap-year calculations).

Included among SCE's critical applications were the financial, customer information and billing, material management, and human resource systems. Work was also completed on critical physical assets in the areas of information technology infrastructure, and embedded processor technology in generation, transmission, distribution and facilities assets. None of SCE's critical applications or assets has encountered significant problems on or since January 1, 2000, and they continue to operate as expected. SCE expects business as usual in 2000, as it relates to its Year 2000 computer system issues.

The other essential component of the Year 2000 program was to identify and assess vendor products and business partners for Year 2000 readiness, as these external parties may have had the potential to impact SCE's Year 2000 readiness. SCE implemented a process to identify and contact vendors and business partners to determine their Year 2000 status. This process included appropriate follow-up and contingency activities.

SCE's Year 2000 costs through December 31, 1999, were \$65 million, of which 37% was for capital costs. SCE's current rate levels for providing electric service were sufficient to provide funding for utility-related modifications.

SCE developed contingency plans, which included provisions for monitoring, validating and managing the continued performance of SCE's Year 2000-sensitive systems and assets during critical transition periods, development of work-arounds and expedited fix-on-failure strategies. These contingency plans, whose initial development was completed in June 1999, were in place for year-end 1999. SCE will continue to maintain the readiness of its contingency plans throughout 2000. Ongoing efforts include monitoring of systems over the February 29 leap-day period. SCE does not expect the Year 2000 issue to have a material adverse effect on its results of operation or financial position.

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 such important factors as further actions by state and federal regulatory bodies setting rates and implementing the restructuring of the electric utility industry; the effects of new laws and regulations relating to restructuring and other matters; the effects of increased competition in the electric utility business and other energy-related businesses, including direct customer access to retail energy suppliers and the unbundling of revenue cycle services such as metering and billing; changes in prices of electricity and fuel costs; changes in market interest rates; new or increased environmental liabilities; the ability to create and expand new businesses such as telecommunications; and other unforeseen events.

Consolidated Statements of Income

Southern California Edison Company

In thousands	Year ended December 31,	1999	1998	1997
Operating revenue		\$7,522,000	\$7,499,519	\$7,953,386
Fuel		225,388	323,716	881,471
Purchased power — contracts		2,419,147	2,625,900	2,854,002
Purchased power — power exchange — net		759,818	636,343	—
Provisions for regulatory adjustment clauses — net		(763,830)	(472,519)	(410,935)
Other operating expenses		1,556,652	1,480,644	1,216,317
Maintenance		363,359	410,566	405,545
Depreciation, decommissioning and amortization		1,546,312	1,545,735	1,239,878
Income taxes		448,510	445,642	582,031
Property and other taxes		121,359	128,402	129,038
Net gain on sale of utility plant		(3,035)	(542,608)	(3,849)
Total operating expenses		6,673,680	6,581,821	6,893,498
Operating income		848,320	917,698	1,059,888
Provision for rate phase-in plan		—	—	(48,486)
Allowance for equity funds used during construction		13,008	11,826	7,651
Interest and dividend income		69,029	66,725	44,636
Other nonoperating income (deductions) — net		50,709	(4,385)	(23,036)
Total other income (deductions) — net		132,746	74,166	(19,235)
Income before interest expense		981,066	991,864	1,040,653
Interest and amortization on long-term debt		392,894	421,857	345,592
Other interest expense		91,250	64,225	101,078
Allowance for borrowed funds used during construction		(11,288)	(8,046)	(9,213)
Capitalized interest		(1,211)	(1,294)	(2,398)
Total interest and amortization expense — net		471,645	476,742	435,059
Net income		509,421	515,122	605,594
Dividends on preferred stock		25,889	24,632	29,488
Earnings available for common stock		\$ 483,532	\$ 490,490	\$ 576,106

Consolidated Statements of Comprehensive Income

In thousands	Year ended December 31,	1999	1998	1997
Net income		\$ 509,421	\$ 515,122	\$ 605,594
Unrealized gain on securities — net		28,009	9,275	14,641
Reclassification adjustment for gains included in net income		(45,920)	(17,836)	—
Comprehensive income		\$ 491,510	\$ 506,561	\$ 620,235

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

Consolidated Balance Sheets

In thousands	December 31,	1999	1998
ASSETS			
Utility plant, at original cost:			
Transmission and distribution		\$12,439,059	\$11,771,678
Generation		1,717,676	1,689,469
Accumulated provision for depreciation and decommissioning		(7,520,036)	(6,896,479)
Construction work in progress		562,651	516,664
Nuclear fuel, at amortized cost		132,197	172,250
Total utility plant		7,331,547	7,253,582
Nonutility property — less accumulated provision for depreciation of \$6,797 and \$25,682 at respective dates		103,644	56,681
Nuclear decommissioning trusts		2,508,904	2,239,929
Other investments		160,241	179,480
Total investments and other assets		2,772,789	2,476,090
Cash and equivalents		26,046	81,500
Receivables, including unbilled revenue, less allowances of \$24,665 and \$22,230 for uncollectible accounts at respective dates		1,013,661	1,112,630
Fuel inventory		49,989	51,299
Materials and supplies, at average cost		122,866	116,259
Accumulated deferred income taxes — net		188,143	274,833
Regulatory balancing accounts — net		—	287,377
Prepayments and other current assets		111,151	91,992
Total current assets		1,511,856	2,015,890
Unamortized nuclear investment — net		1,365,848	2,161,998
Income tax-related deferred charges		1,272,947	1,463,256
Regulatory balancing accounts — net		1,714,973	361,404
Unamortized debt issuance and reacquisition expense		335,044	348,816
Other deferred charges		1,352,302	865,892
Total deferred charges		6,041,114	5,201,366
Total assets		\$17,657,306	\$16,946,928

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

In thousands, except share amounts	December 31,	1999	1998
CAPITALIZATION AND LIABILITIES			
Common shareholder's equity:			
Common stock (434,888,104 shares outstanding at each date)		\$ 2,168,054	\$ 2,168,054
Additional paid-in capital		335,038	334,031
Accumulated other comprehensive income		21,551	39,462
Retained earnings		608,453	793,625
		3,133,096	3,335,172
Preferred stock:			
Not subject to mandatory redemption		128,755	128,755
Subject to mandatory redemption		255,700	255,700
Long-term debt		5,136,681	5,446,638
Total capitalization		8,654,232	9,166,265
Current portion of long-term debt		571,300	400,810
Short-term debt		795,988	469,565
Accounts payable		573,919	447,484
Accrued taxes		500,709	678,955
Accrued interest		82,554	89,828
Dividends payable		94,407	91,742
Regulatory balancing accounts — net		75,693	—
Deferred unbilled revenue and other current liabilities		1,440,387	1,096,332
Total current liabilities		4,134,957	3,274,716
Accumulated deferred income taxes — net		2,938,661	2,993,142
Accumulated deferred investment tax credits		205,197	250,116
Customer advances and other deferred credits		823,992	795,266
Power purchase contracts		563,459	129,698
Other long-term liabilities		336,473	337,411
Total deferred credits and other liabilities		4,867,782	4,505,633
Minority interest		335	314
Commitments and contingencies (Notes 2, 10, and 11)			
Total capitalization and liabilities		\$17,657,306	\$16,946,928

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

Consolidated Statements of Cash Flows

In thousands	Year ended December 31,	1999	1998	1997
Cash flows from operating activities:				
Net income		\$ 509,421	\$ 515,122	\$ 605,594
Adjustments for non-cash items:				
Depreciation, decommissioning and amortization		1,546,312	1,545,735	1,239,878
Other amortization		95,060	89,323	81,363
Deferred income taxes and investment tax credits		177,599	(94,504)	63,379
Other long-term liabilities		31,112	(12,528)	55,712
Regulatory balancing accounts — long-term		(1,353,570)	(361,403)	—
Regulatory asset related to the sale of generating plants		179	(220,232)	—
Net gain on sale of generating plants		(938)	(564,623)	—
Other — net		(76,125)	7,600	(161,698)
Changes in working capital:				
Receivables		98,969	(206,242)	14,695
Regulatory balancing accounts		363,071	(94,067)	(374,799)
Fuel inventory, materials and supplies		(5,297)	23,481	35,707
Prepayments and other current assets		(19,159)	1,106	12,039
Accrued interest and taxes		(185,520)	174,107	16,625
Accounts payable and other current liabilities		352,489	205,256	120,464
Net cash provided by operating activities		1,533,603	1,008,131	1,708,959
Cash flows from financing activities:				
Long-term debt issued		490,840	—	—
Long-term debt repaid		(362,872)	(776,030)	(916,145)
Rate reduction notes issued		—	—	2,449,289
Rate reduction notes repaid		(246,300)	(251,591)	—
Preferred stock redeemed		—	(74,300)	(100,000)
Nuclear fuel financing — net		(37,287)	16,244	(20,140)
Short-term debt issued — net		326,423	147,537	91,879
Capital transferred		—	—	153,000
Dividends paid		(685,731)	(1,129,812)	(1,871,944)
Net cash used by financing activities		(514,927)	(2,067,952)	(214,061)
Cash flows from investing activities:				
Additions to property and plant		(984,197)	(860,837)	(685,320)
Proceeds from sale of generating plants		—	1,203,039	—
Funding of nuclear decommissioning trusts		(115,937)	(162,925)	(153,756)
Unrealized gain (loss) in equity investments — net		(17,911)	(8,561)	14,641
Other — net		43,915	8,333	(28,133)
Net cash provided (used) by investing activities		(1,074,130)	179,049	(852,568)
Net increase (decrease) in cash and equivalents		(55,454)	(880,772)	642,330
Cash and equivalents, beginning of year		81,500	962,272	319,942
Cash and equivalents, end of year		\$ 26,046	\$ 81,500	\$ 962,272

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

**Consolidated Statement of Changes in Common
Shareholder's Equity**

Southern California Edison Company

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 1996	\$ 2,168	\$ 178	\$ 33	\$2,666	\$5,045
Net income				606	606
Unrealized gain on securities			24		24
Tax effect			(9)		(9)
Dividends declared on common stock				(1,829)	(1,829)
Dividends declared on preferred stock				(30)	(30)
Reacquired capital stock expense				(5)	(5)
Additional investment from parent company		156			156
Balance at December 31, 1997	2,168	334	48	1,408	3,958
Net income				515	515
Unrealized gain on securities			14		14
Tax effect			(5)		(5)
Reclassified adjustment for gain Included in net income			(30)		(30)
Tax effect			12		12
Dividends declared on common stock				(1,101)	(1,101)
Dividends declared on preferred stock				(24)	(24)
Stock option appreciation				(4)	(4)
Balance at December 31, 1998	2,168	334	39	794	3,335
Net income				509	509
Unrealized gain on securities			46		46
Tax effect			(17)		(17)
Reclassified adjustment for gain Included in net income			(77)		(77)
Tax effect			31		31
Dividends declared on common stock				(666)	(666)
Dividends declared on preferred stock				(26)	(26)
Stock option appreciation				(3)	(3)
Capital stock expense		1			1
Balance at December 31, 1999	\$ 2,168	\$ 335	\$ 22	\$ 608	\$3,133

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 which supplies electric energy for its 4.3 million customers in central, coastal and Southern California. SCE also produces electricity. The regulatory environment in which SCE operates is changing as a result of a 1995 California Public Utilities Commission (CPUC) decision on electric utility industry restructuring and state legislation enacted in 1996.

Basis of Presentation

SCE's accounting policies conform with generally accepted accounting principles, including the accounting principles for rate-regulated enterprises which reflect the rate-making policies of the CPUC and the Federal Energy Regulatory Commission (FERC). As a result of industry restructuring state legislation and related changes in the rate-recovery of generation-related assets, SCE accounts for its investment in generation facilities in accordance with accounting principles applicable to enterprises in general. Application of such accounting principles to SCE's generation assets began in 1997 and did not result in any adjustment of their carrying value; however, the carrying value of SCE's nuclear investments (excluding decommissioning) was reduced by \$2.6 billion and a regulatory asset was established for the same amount.

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, 1999, financial statement presentation.

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

Estimates

Financial statements prepared in compliance with generally accepted accounting principles 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, decommissioning and contingencies are further discussed in Notes 2, 10 and 11 to the Consolidated Financial Statements, respectively.

Cash Equivalents

Cash equivalents include tax-exempt investments and time deposits and other investments with maturities of three months or less.

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.

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year.

Investments

Net unrealized gains (losses) on equity securities 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.

Regulation of Utility Business

SCE, which is subject to rate-regulation by the CPUC and the FERC, operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory.

Effective January 1, 1998, SCE's rates were unbundled into separate charges for energy, transmission, distribution, the non-bypassable competition transition charge (CTC), public benefit programs and nuclear decommissioning. The transmission component is being collected through FERC-approved rates, subject to refund. SCE's costs associated with its hydroelectric plants are being recovered through a performance-based mechanism. This mechanism sets the hydroelectric revenue requirement and establishes a formula for extending it through the duration of the electric industry restructuring transition period (March 31, 2002), or until market valuation of the hydroelectric facilities, whichever occurs first. (See Hydroelectric Market Value Filing discussion in Note 2.) Revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement is credited against the costs to transition to a competitive market. Decommissioning costs are being recovered through a CPUC-authorized non-bypassable charge.

The CTC provides SCE the opportunity to recover its costs to transition to a competitive market (approximately \$10.6 billion 1998 net present value). Transition costs related to power-purchase contracts are being recovered through the terms of the contracts while most of the remaining transition costs will be recovered through 2001. A portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, has been financed by the issuance of rate reduction notes, allowing SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. The notes allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period. Additionally, the state legislation contained provisions for the recovery (through 2006) of reasonable employee-related transition costs, incurred and projected, for retraining, severance, early retirement, outplacement and related expenses.

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1999, SCE had the capacity to pay \$433 million in additional dividends and continue to maintain its authorized capital structure.

Since April 1, 1998, when the new market structure began, SCE has been selling all of its electric generation through the California Power Exchange (PX), as mandated by the CPUC's 1995 restructuring decision. Through the PX, SCE satisfies the electric energy needs of customers who did not choose an alternative energy provider. These transactions through the PX are reported as Purchased power — power exchange — net.

Transactions through the PX were:

In millions	Year Ended December 31,	1999	1998
Purchases		\$ 2,479	\$ 1,984
Generation sales		1,719	1,348
Purchased power — PX — net		\$ 760	\$ 636

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

Notes to Consolidated Financial Statements

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. SCE's discontinuance of accounting principles for rate-regulated enterprises to its generation assets did not result in a write-off of its generation-related regulatory assets since the CPUC has approved recovery of these assets through the CTC.

Regulatory assets and liabilities included in the consolidated balance sheets are:

In millions	December 31, 1999	December 31, 1998
Generation-related:		
Unamortized nuclear investment — net	\$1,366	\$2,162
Flow-through taxes	306	614
Rate reduction notes — transition cost deferral	707	315
Unamortized loss on sale of plant	122	183
Purchased-power settlements	531	130
Environmental remediation	16	16
Regulatory balancing accounts and other	1,075	354
Subtotal	4,123	3,774
Other:		
Flow-through taxes	967	849
Unamortized loss on reacquired debt	295	308
Environmental remediation	111	125
Regulatory balancing accounts and other	(36)	110
Subtotal	1,337	1,392
Total	\$5,460	\$5,166

Generation-related regulatory assets and liabilities are being recovered through the CTC through March 31, 2002, except for the rate reduction notes regulatory asset which will be recovered over the terms of the rate reduction notes. The other regulatory assets and liabilities are being recovered through other components of the unbundled rates.

The unamortized nuclear investment regulatory asset was created during the second quarter of 1998. 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 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. This reclassification had no effect on SCE's results of operations.

If during the transition period events were to occur that made the recovery of these generation-related regulatory assets no longer probable, SCE would be required to write off the remaining balance of such assets (approximately \$2.6 billion, after tax, at December 31, 1999) as a one-time, non-cash charge against earnings.

Regulatory Balancing Accounts

Beginning January 1, 1998, the difference between generation-related revenue and generation-related costs is being accumulated in the transition cost balancing account, effectively eliminating all other balancing accounts except those used to assist in the administration of public purpose funds. Additionally, gains resulting from the sale of the gas- and oil-fueled generation plants during 1998 were credited to the transition cost balancing account; the losses are being amortized over the remaining transition period and accumulated in the transition cost balancing account. These transition costs are being recovered from utility customers (with interest) through the CTC mechanism.

Prior to January 1, 1998, the differences between CPUC-authorized and actual base-rate revenue from kilowatt-hour sales and CPUC-authorized and actual energy costs were accumulated in balancing accounts until they were refunded to, or recovered from, utility customers through authorized rate adjustments (with interest). On January 1, 1998, the balances in these balancing accounts were transferred to the transition cost balancing account.

Income tax effects on all balancing account changes are deferred.

Nuclear

SCE is recovering its investment 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 will continue through December 2001, earning a 7.35% fixed rate of return. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are recovered through an incentive pricing plan which allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price will 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, are subject to balancing account treatment through 2001.

Beginning January 1, 1998, San Onofre's incentive pricing plan and accelerated plant recovery and the Palo Verde balancing account became part of the transition cost balancing account. SCE will be required to share equally with ratepayers the net benefits received from operation of Palo Verde, beginning in 2002, and from the operation of the San Onofre units in 2004. Palo Verde's existing nuclear unit incentive procedure will continue only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle.

Utility Plant

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. 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.

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 1999, 4.2% for 1998 and 5.2% for 1997.

SCE's net investment in generation-related utility plant was \$1.0 billion at December 31, 1999, and \$1.1 billion at December 31, 1998.

Supplemental Cash Flows Information

SCE's supplemental cash flows information was:

In millions	Year ended December 31,	1999	1998	1997
Payments for interest and taxes:				
Interest — net of amounts capitalized		\$ 287	\$ 264	\$ 342
Taxes		433	405	438

Notes to Consolidated Financial Statements

Note 2. Regulatory Matters

FERC Transmission Rate Case

SCE filed its first FERC transmission rate case in March 1997. The filing proposed a transmission revenue requirement of \$211 million. In March 1999, a proposed FERC decision was issued recommending a return on equity of 9.68% (compared to SCE's current CPUC rate for distribution of 11.6%) and a lower revenue requirement. SCE filed comments opposing the proposed decision in May 1999. In response to a recent FERC ruling, on November 1, 1999, SCE filed additional evidence regarding return on equity. A final FERC decision is expected in the first quarter of 2000. SCE does not expect the final decision to have a material effect on its results of operations or financial position.

Hydroelectric Market Value Filing

In order to comply with the restructuring legislation passed in 1996, on December 15, 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately \$1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based and revenue-sharing mechanism. The application had broad-based support from labor, ratepayer and environmental groups. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-index operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfalls from ratepayers. A final CPUC decision is expected by the end of 2000.

Note 3. Financial Instruments

Derivative Financial Instruments

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

SCE uses the hedge accounting method to record its derivative financial instruments, except for gas call options and PX block forward transactions. Hedge accounting requires an assessment that the transaction reduces risk, that the derivative be designated as a hedge at the inception of the derivative contract, and that the changes in the market value of a hedge move in an inverse direction to the item being hedged. Under hedge accounting, the derivative itself is not recorded on SCE's balance sheet. Mark-to-market accounting would be used if the hedge accounting criteria were not met. Interest rate differentials and amortization of premiums for interest rate caps are recorded as adjustments to interest expense. If the derivatives were terminated before the maturity of the corresponding debt issuance, the realized gain or loss on the transaction would be amortized over the remaining term of the debt.

SCE has gas call options that mitigate its exposure to increases in natural gas prices. Increases in natural gas prices tend to increase the price of electricity purchased from the PX. The options cover various periods from 1998 through 2001. Additionally, SCE participates in the PX block forward market. The PX block forward market allows SCE to purchase monthly blocks of energy for six days a week (excluding Sundays and holidays) for 16 hours a day. These purchases can be made up to 12 months in advance of the delivery date. The CPUC has currently limited SCE's use of the PX block forward market to a maximum of approximately 2,000 MW in any month.

SCE uses the mark-to-market accounting method for its gas call options and block forward purchases. Gains and losses from monthly changes in market prices are recorded as income or expense. However, costs of the options and the market price changes are included in the transition cost balancing account. As a result, the mark-to-market gains or losses have no effect on earnings.

Interest rate swaps are used to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At the balance sheet dates of December 31, 1999, and December 31, 1998, SCE had an interest rate swap agreement which fixed the interest rate at 5.585% for \$196 million of debt due 2008; it expires February 28, 2008. The interest rate swap agreement requires the parties to pledge collateral according to bond rating and market interest rate changes. At December 31, 1999, SCE had pledged \$11 million as collateral due to a decline in market interest rates. SCE is exposed to credit loss in the event of nonperformance by the counterparty to the agreement, but does not expect the counterparty to fail to meet its obligation.

Fair Value of Financial Instruments

Fair values of financial instruments were:

In millions	December 31,		1998	
	Cost Basis	Fair Value	Cost Basis	Fair Value
Financial assets:				
Decommissioning trusts	\$1,650	\$2,509	\$1,534	\$2,240
Equity investments	—	33	7	72
Gas call options	28	20	39	31
PX block forward power contracts	118	120	—	—
Financial liabilities:				
DOE decommissioning and decontamination fees	40	35	45	40
Interest rate hedges	—	13	—	28
Long-term debt	5,137	5,044	5,447	5,699
Preferred stock subject to mandatory redemption	256	259	256	274

Financial assets are carried at their fair value based on quoted market prices for decommissioning trusts, equity investments, and on financial models for gas call options. Financial liabilities are recorded at cost. Financial liabilities' fair values are based on: termination costs for the interest rate swap; brokers' quotes for long-term debt and preferred stock; and discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees. Due to their short maturities, amounts reported for cash equivalents and short-term debt approximate fair value.

Gross unrealized holding gains (losses) on debt and equity investments were:

In millions	December 31,	1999	1998
Decommissioning trusts:			
Municipal bonds		\$239	\$196
Stocks		454	365
U.S. government issues		119	115
Short-term and other		47	30
		859	706
Equity investments		33	65
Total		\$892	\$771

There were no unrealized holding losses for the years presented.

In 1998, a new accounting standard for derivative instruments and hedging activities was issued. The new standard, which will be effective January 1, 2001, requires all derivatives to be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses

Notes to Consolidated Financial Statements

from hedges of a forecasted transaction or foreign currency exposure would be reflected in other comprehensive income. Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE anticipates that most of its derivatives under the new standard would qualify for hedge accounting. SCE expects to recover in rates any market price changes from its derivatives that could potentially affect earnings. Accordingly, implementation of this new standard is not expected to affect earnings.

Note 4. 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 arranged with securities dealers to remarket or purchase them if necessary.

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 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.

Long-term debt maturities and sinking-fund requirements for the five years are: 2000 — \$571 million; 2001 — \$646 million; 2002 — \$446 million; 2003 — \$371 million; and 2004 — \$371 million.

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 generally accepted accounting principles, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Long-term debt consisted of:

In millions	December 31,	1999	1998
First and refunding mortgage bonds: 2000 - 2026 (5.625% to 7.25%)		\$1,400	\$1,550
Rate reduction notes: 2000 - 2007 (6.14% to 6.42%)		1,970	2,217
Pollution-control bonds: 2008 - 2031 (5.125% to 7.2% and variable)		1,196	1,201
Funds held by trustees		(2)	(2)
Debentures and notes: 2000 - 2029 (5.875% to 8.25%)		1,000	700
Subordinated debentures: 2044 (8.375%)		100	100
Commercial paper for nuclear fuel		71	108
Long-term debt due within one year		(571)	(401)
Unamortized debt discount — net		(27)	(26)
Total		\$5,137	\$5,447

On January 24, 2000, SCE issued \$250 million of 7-5/8% notes, due 2010.

Note 5. Short-Term Debt

SCE has lines of credit totaling \$1.25 billion (that can be used at negotiated or bank index rates) with \$39 million available for general purpose short-term debt and \$515 million available for the long-term refinancing of certain variable-rate pollution-control debt.

Short-term debt includes commercial paper used to finance fuel inventories and general cash requirements. 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. Weighted-average interest rates were 6.1% and 5.3% at December 31, 1999, and December 31, 1998, respectively.

Short-term debt consisted of:

In millions	December 31,	1999	1998
Commercial paper		\$696	\$581
Floating rate notes		175	—
Amount reclassified as long-term debt		(71)	(108)
Unamortized discount		(4)	(3)
Total		\$796	\$470

Note 6. Preferred Stock

Authorized shares of preferred and preference stock are: \$25 cumulative preferred — 24 million; \$100 cumulative preferred — 12 million; and preference — 50 million. All cumulative preferred stock is redeemable.

Mandatorily redeemable preferred stock is subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Notes to Consolidated Financial Statements

Preferred stock redemption requirements for the next five years are: 2000 and 2001 — zero; 2002 — \$105 million; 2003 — \$9 million; and 2004 — \$9 million.

Cumulative preferred stock consisted of:

Dollars in millions, except per share amounts	December 31,		1999	1998
	December 31, 1999			
	Shares Outstanding	Redemption Price		
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
Total			\$256	\$256

In 1998, 193,000 shares of Series 7.23% preferred stock and 2.2 million shares of 5.8% preferred stock were redeemed. There were no preferred stock issuances for the years presented.

Note 7. Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under income tax allocation agreements, each subsidiary calculates its own tax liability.

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,	1999	1998
Deferred tax assets:			
Property-related		\$ 184	\$ 197
Unrealized gains or losses		453	387
Investment tax credits		113	152
Regulatory balancing accounts		67	96
Decommissioning-related		127	126
Fixed costs		247	188
Unbilled revenue		122	117
Other		92	168
Total		\$1,405	\$1,431
Deferred tax liabilities:			
Property-related		\$2,629	\$3,005
Capitalized software costs		225	196
Regulatory balancing accounts		448	162
Unrealized gains and losses - decommissioning		351	284
Other		502	502
Total		\$4,155	\$4,149
Accumulated deferred income taxes — net		\$2,750	\$2,718
Classification of accumulated deferred income taxes:			
Included in deferred credits		\$2,938	\$2,993
Included in current assets		188	275

The current and deferred components of income tax expense were:

In millions	Year ended December 31,	1999	1998	1997
Current:				
Federal		\$299	\$450	\$375
State		79	101	100
		378	551	475
Deferred—federal and state:				
Accrued charges		(76)	(43)	(33)
Property related		(187)	(106)	(47)
Investment and energy tax credits — net		(45)	(74)	(20)
Pension reserve		1	(3)	(5)
Rate phase-in plan		—	—	(19)
Regulatory balancing accounts		371	177	141
Unbilled revenue		(5)	(67)	6
Other		1	7	22
		60	(109)	45
Total income tax expense		\$438	\$442	\$520
Classification of income taxes:				
Included in operating income		\$449	\$446	\$582
Included in other income		(11)	(4)	(62)

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

Notes to Consolidated Financial Statements

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

Year ended December 31,	1999	1998	1997
Federal statutory rate	35.0%	35.0%	35.0%
Capitalized software	(2.4)	(0.7)	(0.9)
Property-related and other	9.3	11.4	6.9
Investment and energy tax credits	(4.4)	(6.8)	(1.8)
State tax — net of federal deduction	8.5	6.9	7.0
Effective tax rate	46.0%	45.8%	46.2%

Note 8. Employee Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed as a source of employees' retirement income. The plan received employer contributions of \$25 million in 1999, \$17 million in 1998 and \$15 million in 1997.

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.

In 1998, SCE adopted a new accounting standard that revises the disclosure requirements for pension plans. Prior years have been restated.

Information on plan assets and benefit obligations is shown below:

In millions	Year ended December 31,	1999	1998
Change in benefit obligation			
Benefit obligation at beginning of year		\$2,251	\$2,094
Service cost		66	59
Interest cost		146	141
Plan amendment		(22)	—
Actuarial loss (gain)		(224)	90
Benefits paid		(142)	(133)
Benefit obligation at end of year		\$2,075	\$2,251
Change in plan assets			
Fair value of plan assets at beginning of year		\$2,552	\$2,298
Actual return on plan assets		620	334
Employer contributions		48	53
Benefits paid		(142)	(133)
Fair value of plan assets at end of year		\$3,078	\$2,552
Funded status		\$1,003	\$ 301
Unrecognized net loss (gain)		(1,018)	(372)
Unrecognized transition obligation		28	33
Unrecognized prior service cost		132	168
Recorded asset		\$ 145	\$ 130
Discount rate		7.75%	6.75%
Rate of compensation increase		5.0%	5.0%
Expected return on plan assets		7.5%	7.5%

Expense components were:

In millions	Year ended December 31,	1999	1998	1997
Service cost		\$ 66	\$ 59	\$ 44
Interest cost		146	141	138
Expected return on plan assets		(188)	(170)	(160)
Net amortization and deferral		12	14	13
Pension expense under accounting standards		36	44	35
Regulatory adjustment — deferred		14	11	17
Total expense recognized		\$ 50	\$ 55	\$ 52

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. In 1998, SCE adopted a new accounting standard that revises the disclosure requirements for postretirement benefit plans. Prior periods have been restated.

Information on plan assets and benefit obligations is shown below:

In millions	Year ended December 31,	1999	1998
Change in benefit obligation			
Benefit obligation at beginning of year		\$1,545	\$1,533
Service cost		46	41
Interest cost		109	99
Actuarial loss (gain)		(185)	(74)
Benefits paid		(53)	(54)
Benefit obligation at end of year		\$1,462	\$1,545
Change in plan assets			
Fair value of plan assets at beginning of year		\$1,029	\$ 815
Actual return on plan assets		185	147
Employer contributions		122	121
Benefits paid		(53)	(54)
Fair value of plan assets at end of year		\$1,283	\$1,029
Funded status		\$ (179)	\$ (516)
Unrecognized net loss (gain)		(207)	84
Unrecognized transition obligation		349	376
Recorded asset (liability)		\$ (37)	\$ (56)
Discount rate		8.0%	6.75%
Expected return on plan assets		7.5%	7.5%

Expense components were:

In millions	Year ended December 31,	1999	1998	1997
Service cost		\$ 46	\$ 41	\$ 30
Interest cost		109	99	99
Expected return on plan assets		(79)	(62)	(50)
Net amortization and deferral		27	28	31
Total expense		\$ 103	\$ 106	\$ 110

Notes to Consolidated Financial Statements

The assumed rate of future increases in the per-capita cost of health care benefits is 11.75% for 2000, 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, 1999, by \$227 million and annual aggregate service and interest costs by \$28 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 1999, by \$183 million and annual aggregate service and interest costs by \$22 million.

Stock Option Plans

In 1998, Edison International shareholders approved the Edison International Equity Compensation Plan. The plan replaces the Long-Term Incentive Compensation Program, consisting of officer, director, and management plans, which was adopted by Edison International shareholders in 1992. No new awards will be made under the prior program; however, it will remain in effect as long as any awards remain outstanding under the prior program.

The prior program participated in the use of 8.2 million shares of parent company common stock reserved for potential issuance under various stock compensation programs to directors, officers and senior managers of Edison International and its affiliates. Under these programs, options on 2.7 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

The new plan authorizes the annual issuance of shares equal to one percent of the issued and outstanding shares of Edison International common stock as of December 31 of the prior year. This authorization is cumulative so that to the extent shares are not needed to meet new plan requirements in any year, the excess authorized shares will carry over to subsequent years until plan termination. One percent of the issued and outstanding Edison International common stock on December 31, 1998 and December 31, 1997, was 3.5 million and 3.8 million shares, respectively. Under the new plan, options on 4.0 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

Each option may be exercised to purchase one share of Edison International common stock, and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Edison International stock options include a dividend equivalent feature. Generally, for options issued before 1994, amounts equal to dividends accrue on the options at the same time and at the same rate as would be payable on the number of shares of Edison International common stock covered by the options. The amounts accumulate without interest. For Edison International stock options issued after 1993, dividend equivalents are subject to reduction unless certain shareholder return performance criteria are met. Beginning with the 1999 Edison International stock option awards, only some stock options include a dividend equivalent feature. Future stock option awards under the plan are not expected to include the dividend equivalent feature. Additionally, awards of performance shares, comprising a combination of Edison International common stock and cash, are anticipated under the plan.

The new plan's stock options have a 10-year term with one-fourth of the total award vesting after each of the first four years of the award term. The prior program's stock options have a 10-year term with one-third of the total award vesting after each of the first three years of the award term. If an optionee retires, dies or is permanently and totally disabled during the vesting period, the unvested options will vest and be exercisable to the extent of 1/36 (prior program) or 1/48 (the new plan) of the grant for each full month of service during the vesting period.

Unvested options of any person who has served in the past on the Edison International or SCE Management Committee (which was dissolved in 1993) will vest and be exercisable upon the member's retirement, death or permanent and total disability. Upon retirement, death or permanent and total disability, the vested options may continue to be exercised within their original terms by the recipient or beneficiary. If an optionee is terminated other than by retirement, death or permanent and total disability, 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.

SCE measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation program was \$5 million, \$8 million and \$5 million for the years 1999, 1998 and 1997, respectively.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma earnings of \$509 million, \$516 million and \$602 million for the years 1999, 1998 and 1997, respectively.

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:

	1999	1998
Expected life	7 years	7 years
Risk-free interest rate	5.0% - 5.5%	4.7% - 5.6%
Expected volatility	18%	17%

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 1999 and 1998 was \$4.37 per share option and \$6.44 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 1999, and December 31, 1998, was 7 years.

Note 9. 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 included in the consolidated balance sheet as of December 31, 1999, was:

In millions	Original Cost of Facility	Accumulated Depreciation and Amortization	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	\$ 39	\$ 6	\$ 3	60%
Pacific Intertie	241	78	6	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	459	325	3	48
Mohave (coal)	323	217	2	56
Palo Verde (nuclear) ⁽¹⁾	1,609	1,153	19	16
San Onofre (nuclear) ⁽¹⁾	4,275	3,269	16	75
Total	\$6,946	\$5,048	\$49	

⁽¹⁾ Reported as Unamortized nuclear investment — net."

Notes to Consolidated Financial Statements

Note 10. Commitments

Leases

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

Estimated remaining commitments for noncancellable leases at December 31, 1999, were:

Year ended December 31,	In millions
2000	\$13
2001	10
2002	7
2003	5
2004	4
Thereafter	8
Total	\$47

Nuclear Decommissioning

Decommissioning is estimated to cost \$2.0 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 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 2013 for San Onofre Units 2 and 3, and 2025—2027 for Palo Verde. Decommissioning costs, which are accrued and recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

In June 1999, the CPUC authorized SCE to access its nuclear decommissioning trust funds to start decommissioning San Onofre Unit 1 (shutdown in 1992 per CPUC agreement) effective immediately.

Decommissioning expense was \$124 million in 1999, \$164 million in 1998 and \$154 million in 1997. The accumulated provision for decommissioning, excluding San Onofre Unit 1, was \$1.3 billion at December 31, 1999, and \$1.2 billion at December 31, 1998. The estimated costs to decommission San Onofre Unit 1 (approximately \$360 million) are 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, 1999	1998
Municipal bonds	2000—2033	\$ 684	\$ 547
Stocks	—	482	550
U.S. government issues	2000—2030	351	355
Short-term and other	2000—2040	133	82
Trust fund balance		\$1,650	\$1,534

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were \$58 million in 1999, \$63 million in 1998 and \$54 million in 1997. Proceeds from sales of securities (which are reinvested) were \$2.6 billion in 1999, \$1.2 billion in 1998 and \$595 million in 1997. Approximately 90% 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. Additionally, SCE's 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 qualifying facilities (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. As a result of the utility industry restructuring, SCE has entered into purchased-power settlements to end its contract obligations with certain qualifying facilities. The settlements are reported as long-term liabilities. Settlement payments are being recovered through the CTC.

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 \$166 million through 2017. The purchased-power contract (approximately \$30 million) is expected to provide approximately 5.5% of current or estimated future operating capacity, and is reported as a long-term liability. The transmission service contract requires a minimum payment of approximately \$6 million a year.

Certain commitments for the years 2000 through 2004 are estimated below:

In millions	2000	2001	2002	2003	2004
Projected construction expenditures	\$1,108	\$1,030	\$908	\$901	\$890
Fuel supply contracts	180	123	132	142	121
Purchased-power capacity payments	793	783	683	668	678

Note 11. Contingencies

In addition to the matters disclosed in these notes, SCE is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Environmental 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

Notes to Consolidated Financial Statements

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 45 identified sites is \$163 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 \$284 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In 1998, SCE sold all of its gas- and oil-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 42 of its sites, representing \$90 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 \$126 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 \$5 million to \$15 million. Recorded costs for 1999 were \$14 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range 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 \$19 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.

SCE 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. Meeting spent-fuel storage requirements beyond that period would require new and separate interim storage facilities, the costs for which have not been determined. 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.

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.

SCE and other owners of nuclear power plants may be able to recover interim storage costs arising from DOE delays in the acceptance of utility spent nuclear fuel by pursuing relief under the terms of the contracts, as directed by the courts, or through other court actions.

Quarterly Financial Data

In millions	1999					1998				
	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue	\$7,522	\$1,820	\$2,304	\$1,721	\$1,677	\$7,500	\$1,889	\$2,369	\$1,619	\$1,623
Operating income	848	221	257	198	172	918	241	237	212	228
Net income	509	146	168	112	83	515	121	169	120	105
Earnings available for										
common stock	484	141	160	106	77	490	115	163	114	98
Common dividends declared	666	117	269	111	169	1,101	141	422	442	96

Responsibility for Financial Reporting

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 its 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*



Stephen E. Frank
*Chairman of the Board, President
and Chief Executive Officer*

February 2, 2000

To the Shareholders and the Board of Directors,
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, 1999, and 1998, and the related consolidated statements of income, comprehensive income, cash flows and common shareholder's equity for each of the three years in the period ended December 31, 1999. 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, 1999, and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.


ARTHUR ANDERSEN LLP

Los Angeles, California
February 2, 2000

Selected Financial and Operating Data: 1995-1999

Southern California Edison Company

Dollars in millions

	1999	1998	1997	1996	1995
Income statement data:					
Operating revenue	\$ 7,522	\$ 7,500	\$ 7,953	\$ 7,583	\$ 7,873
Operating expenses ⁽¹⁾	6,674	6,582	6,893	6,450	6,724
Fuel and purchased power expenses	3,404	3,586	3,735	3,336	3,197
Income tax from operations	449	446	582	578	560
Allowance for funds used during construction	24	20	17	25	34
Interest expense — net	483	485	444	453	464
Net income	509	515	606	655	680
Earnings available for common stock	484	490	576	621	643
Ratio of earnings to fixed charges	2.94	2.95	3.49	3.54	3.52

Balance sheet data:

Assets	\$17,657	\$16,947	\$18,059	\$17,737	\$18,155
Gross utility plant	14,852	14,150	21,483	21,134	20,717
Accumulated provision for depreciation and decommissioning	7,520	6,896	10,544	9,431	8,569
Common shareholder's equity	3,133	3,335	3,958	5,045	5,144
Preferred stock:					
Not subject to mandatory redemption	129	129	184	284	284
Subject to mandatory redemption	256	256	275	275	275
Long-term debt	5,137	5,447	6,145	4,779	5,215
Capital structure:					
Common shareholder's equity	36.2%	36.4%	37.5%	48.6%	47.1%
Preferred stock:					
Not subject to mandatory redemption	1.5%	1.4%	1.7%	2.7%	2.6%
Subject to mandatory redemption	2.9%	2.8%	2.6%	2.7%	2.5%
Long-term debt	59.4%	59.4%	58.2%	46.0%	47.8%

Operating data:

Peak demand in megawatts (MW)	19,122	19,935	19,118	18,207	17,548
Generation capacity at peak (MW)	10,474	10,546	21,511	21,602	21,603
Kilowatt-hour sales (kWh) (in millions)	78,602	76,595	77,234	75,572	74,296
Total energy requirement (kWh) (in millions) ⁽²⁾	78,752	80,289	86,849	84,236	81,924
Energy mix:					
Thermal	35.5%	38.8%	44.6%	47.6%	51.6%
Hydro	5.6%	7.4%	6.5%	6.9%	7.7%
Purchased power and other sources	58.9%	53.8%	48.9%	45.5%	40.7%
Customers (in millions)	4.36	4.27	4.25	4.22	4.18
Full-time employees	13,040	13,177	12,642	12,057	14,886

⁽¹⁾ 1999 and 1998 includes net purchases from the PX.⁽²⁾ 1999 and 1998 excludes direct access and resale customer requirements.

Board of Directors**Southern California Edison Company**

Winston H. Chen*
Chairman of the Paramitas Foundation
and Chairman of Paramitas
Investment Corporation,
Santa Clara, California

Warren Christopher
Senior Partner,
O'Melveny & Myers,
Los Angeles, California

Stephen E. Frank
Chairman of the Board, President and
Chief Executive Officer,
Southern California Edison Company

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

Carl F. Huntsinger
General Partner,
DAE Limited Partnership Ltd.,
Ojai, California

*Retiring on April 20, 2000.

Charles D. Miller
Chairman of the Board,
Avery Dennison Corporation,
Pasadena, California

Luis G. Nogales
President,
Nogales Partners,
Los Angeles, California

Ronald L. Olson
Senior Partner,
Munger, Tolles and Olson,
Los Angeles, California

James M. Rosser
President,
California State University, Los Angeles,
Los Angeles, California

Robert H. Smith
Managing Director,
Smith and Crowley Incorporated,
Pasadena, California

Thomas C. Sutton
Chairman of the Board and
Chief Executive Officer
Pacific Life Insurance Company,
Newport Beach, California

Daniel M. Tellep
Retired Chairman of the Board,
Lockheed Martin Corporation,
Bethesda, Maryland

Edward Zapanta, M.D.
Physician and Neurosurgeon,
Torrance, California

Management Team

Stephen E. Frank
Chairman of the Board, President and
Chief Executive Officer

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

Robert G. Foster
Senior Vice President,
Public Affairs

Lillian R. Gorman*
Senior Vice President,
Human Resources

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

Bruce C. Foster
Vice President,
San Francisco Regulatory Operations

A. L. Grant
Vice President, Transmission

Lawrence D. Hamlin
Vice President, Power Production and
Operations and Maintenance Services

Holly Kolinski
Vice President,
Mass Customers

R. W. Krieger
Vice President,
Nuclear Generation

J. Michael Mendez
Vice President, Labor Relations

Thomas M. Noonan
Vice President and Controller

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

Stephen E. Pickett
Vice President and General Counsel

Frank J. Quevedo
Vice President,
Equal Opportunity

Joseph P. Ruiz
Vice President and General Auditor

W. James Scilacci
Vice President and
Chief Financial Officer

Dale E. Shull, Jr.
Vice President, Distribution

Anthony L. Smith
Vice President, Tax

David Ned Smith
Vice President, Major Customers

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

Robert C. Boada
Treasurer

Beverly P. Ryder
Secretary

*Resigned on February 29, 2000.

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Shareholder Information

Annual Meeting of Shareholders

Thursday, April 20, 2000
9:00 a.m., Central Time
Chicago Public Library
Harold Washington Library Center
400 South State Street
Chicago, Illinois 60605

Stock Listing and Trading Information

SCE Preferred Stock

The American and Pacific stock exchanges use the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange table under the symbol SoCalEd. 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

Norwest Bank Minnesota, N.A. maintains shareholder records and is transfer agent and registrar for SCE preferred stock. Shareholders may call Norwest Shareowner Services, (800) 347-8625, between 7:00 a.m. and 7:00 p.m. (Central Time) every business day, 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;
- dividend checks;
- requests to eliminate multiple annual report mailings; and
- requests for access to online account information.

The address of Norwest Shareowner Services is:

P.O. Box 64854, St. Paul, Minnesota 55164-0854
FAX: (651) 450-4033



SOUTHERN CALIFORNIA
EDISON

An EDISON INTERNATIONAL™ Company

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