SOUTHERN CALIFORNIA

EDISON

An *EDISON INTERNATIONAL*℠ Company

1998 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 113-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.

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Results of Operations

Earnings

Southern California Edison Company's (SCE) 1998 earnings were $490 million, compared with $576 million in 1997 and $621 million in 1996. SCE's 1996 earnings included special charges of $18 million for workforce management costs and reserves. The $86 million earnings decline in 1998 was primarily 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 gas- and oil-fueled generation assets, partially offset by superior operating performance at the San Onofre Nuclear Generating Station. Before special charges, 1997 earnings declined $63 million compared to the prior year, mainly due to the extended outage and lower return at San Onofre. The decline was partially offset by higher sales and lower non-nuclear operating expenses.

Operating Revenue

Since April 1, 1998, SCE has been required to sell all of its generated power to the power exchange (PX). For more details, see Competitive Environment. Excluding the sales to the PX, operating revenue decreased 6% from 1997. The decrease reflects lower average residential rates (mandated by legislation enacted in September 1996), partially offset by an increase in other revenue resulting from maintenance work SCE is providing for the new owners of the divested gas- and oil-fueled plants, as required by the restructuring legislation. Operating revenue increased 5% in 1997 over 1996, due to an increase in sales volume and customer refunds in 1996. There were no comparable refunds in 1997. The increase in volume is mainly attributable to the overall increase in retail sales among residential and commercial customers due to unusually warm weather during the third quarter of 1997. In 1998, over 99% of operating revenue (excluding sales to the PX) 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 (excluding sales to the PX) during the third quarter of each year is significantly higher than other quarters.

The changes in operating revenue (excluding sales to the PX) resulted from:

In millions Year ended December 31,	1998	1997	1996
Operating revenue —			
Rate changes (including refunds)	$(527)	$173	$(522)
Sales volume changes	(44)	193	206
Other	117	4	26
Total	$(454)	$370	$(290)

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

Operating Expenses

Fuel expense decreased 63% in 1998, primarily due to the sale of the gas- and oil-fueled generation plants, as well as significantly lower gas prices in the first quarter of 1998. Fuel expense increased 40% in 1997 over 1996. The increase was due to a $174 million gas contract termination payment during the third quarter of 1997, combined with higher gas prices and the extended refueling outages at San Onofre. San Onofre Unit 2 was shut down during the entire first quarter of 1997, Unit 3 was shut down 80 days of the second quarter and both units had a combined outage time of 30 days during the third

quarter, which resulted in an overall increase in gas-powered generation for 1997. There were no comparable outages in 1996.

Since April 1, 1998, SCE has been required to purchase all of its power from the PX for distribution to its retail customers. SCE is continuing to purchase power from certain nonutility generators (known as qualifying facilities) and under existing inter-utility contracts. This purchased power is sold to the PX. Excluding the power purchased from the PX, purchased-power expense decreased slightly in 1998, while increasing slightly in 1997. SCE is required under federal law to purchase power from certain qualifying facilities even though energy prices under these contracts are generally higher than other sources. In 1998, SCE paid about $1.5 billion (including energy and capacity payments) more for these power purchases than the cost of power available from other sources. The CPUC has mandated the prices for these contracts.

Provisions for regulatory adjustment clauses decreased in 1998, mainly due to the rate-making treatment of the rate reduction notes. This rate-making treatment has allowed for the deferral of the collection of a portion of the transition-related revenue, from a four-year period to a 10-year period. This decrease was almost completely offset by overcollections resulting from the gain on sales of the gas- and oil-fueled generation plants during 1998 and other transition costs, as well as overcollections related to the administration of public-purpose funds. The provisions for regulatory adjustment clauses decreased substantially in 1997, due to undercollections in the energy cost balancing account as actual energy costs (including the gas termination payment discussed above) exceeded CPUC-authorized fuel and purchased-power cost estimates. In addition, there were undercollections associated with SCE's direct access activities (see discussion in Competitive Environment), research and development activities, and San Onofre. These undercollections were offset by overcollections related to actual base-rate revenue from kilowatt-hour sales exceeding CPUC-authorized estimates and the final settlement of SCE's Canadian supply and transportation contracts.

Other operating expenses increased 22% in 1998, primarily due to must-run reliability services, direct access activities, and PX and independent system operator (ISO) costs incurred by SCE. Also, storm damage expense resulting from the harsh winter in 1998 contributed to the increase.

Maintenance expense increased 23% in 1997, due to higher maintenance costs at the transmission and distribution operating facilities, and the scheduled refueling outages at the San Onofre units.

Depreciation, decommissioning and amortization expense increased 25% in 1998, 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 gas- and oil-fueled generation 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. Depreciation, decommissioning and amortization expense increased 17% in 1997, mainly due to increases in plant assets and the accelerated recovery of the Palo Verde units, effective January 1997.

Income taxes decreased 23% in 1998, primarily due to lower pre-tax income, as well as additional amortization related to the CTC mechanism.

Property and other taxes decreased 32% in 1997, due to a reclassification of payroll taxes to operation and maintenance expense.

Gain on sale of utility plant represents the net result from the sale of the gas- and oil-fueled generation plants in 1998. Gains on sales of the gas- and oil-fueled plants were used to reduce stranded costs. Losses on sales will be recovered from customers over the transition period.

Other Income and Deductions

The provision for rate phase-in plan reflected a CPUC-authorized, 10-year rate phase-in plan, which deferred the collection of revenue during the first four years of operation for the Palo Verde units. The deferred revenue (including interest) was collected evenly over the final six years of each unit's plan.

The plan ended in February 1996, September 1996 and January 1998 for Units 1, 2 and 3, respectively. The provision was a non-cash offset to the collection of deferred revenue.

Interest and dividend income increased 49% in 1998, reflecting higher investment balances due to the sale of the gas- and oil-fueled generation plants, as well as increases in interest earned on higher balancing account undercollections. In 1997, interest and dividend income increased 18% due to increases in interest earned on balancing accounts and increases in dividend income from equity investments.

Other nonoperating income increased 81% in 1998, when compared to 1997, primarily due to the additional accruals in 1997 for regulatory matters. These accruals caused a substantial decrease in other nonoperating income in 1997, when compared to 1996.

Interest Expense

Interest on long-term debt increased 22% in 1998, mainly due to the issuance of the rate reduction notes in December 1997. In 1997, interest on long-term debt decreased due to the early retirement of $400 million of first and refunding mortgage bonds in July 1997, partially offset by the additional interest expense associated with the rate reduction notes issued in December 1997. Interest on the rate reduction notes was $148 million in 1998 and $9 million in 1997.

Other interest expense decreased substantially in 1998, 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 gas- and oil-fueled plants. Other interest expense increased substantially in 1997, due to higher levels of short-term debt used to retire first and refunding mortgage bonds.

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 (increased from $2.3 billion in July 1998) of its outstanding shares of common stock. Edison International repurchased 100.4 million shares ($2.4 billion) between January 1995 and February 4, 1999, funded by dividends from its subsidiaries and the issuance of rate reduction notes.

SCE's cash flow coverage of dividends was 0.9 times for both 1998 and 1997 and 2.2 times in 1996. The 1998 decrease reflects the $680 million special dividend SCE paid to Edison International in 1998 from the gas- and oil-fueled plant sales proceeds, as well as the rate-making treatment of the gains on sales of the gas- and oil-fueled plants. The 1997 decrease reflects the $1.2 billion special dividend SCE paid to Edison International in December 1997 from rate reduction note proceeds.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $1.0 billion in 1998, $1.7 billion in 1997 and $1.8 billion in 1996. Cash from operations exceed capital requirements for all years presented.

Cash Flows from Financing Activities

At December 31, 1998, SCE had available lines of $1.3 billion, with $800 million for general purpose, short-term debt and $500 million 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, 1998, SCE could issue approximately $13.9 billion of additional first and refunding mortgage bonds and $4.4 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, 1998, SCE had the capacity to pay $794 million in additional dividends and continue to maintain its authorized capital structure.

In December 1997, SCE Funding LLC, a special purpose entity (SPE), of which SCE is the sole member, issued approximately $2.5 billion of rate reduction notes to Bankers Trust Company of California, as certificate trustee for the California Infrastructure and Economic Development Bank Special Purpose Trust SCE-1 (Trust), which is a special purpose entity established by the State of California. The terms of the rate reduction notes generally mirror the terms of the pass-through certificates issued by the Trust, which are known as rate reduction certificates. The proceeds of the rate reduction notes were used by the SPE to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created pursuant to the restructuring legislation and a financing order of the CPUC, and consists generally of the right to be paid a specified amount from a non-bypassable tariff levied on residential and small commercial customers. Notwithstanding the legal sale of the transition property by SCE to the SPE, the amounts reflected as assets on SCE's balance sheet have not been reduced by the amount of the transition property sold to the SPE, and the liabilities of the SPE for the rate reduction notes are for accounting purposes reflected as long-term liabilities on the consolidated balance sheet of SCE. SCE used the proceeds from the sale of the transition property to retire debt and equity securities.

The rate reduction notes have maturities ranging from one to nine years, and bear interest at rates ranging from 6.14% to 6.42%. The rate reduction notes are secured solely by the transition property and certain other assets of the SPE, and there is no recourse to SCE or Edison International.

Although the SPE is consolidated with SCE in the financial statements, as required by generally accepted accounting principles, the SPE is legally separate from SCE, the assets of the SPE are not available to creditors of SCE or Edison International, and the transition property is legally not an asset of SCE or Edison International.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant, proceeds from the sale of plant (see discussion in Competitive Environment) 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 through charges to depreciation expense. SCE estimates that it will spend approximately $8.6 billion between 2000—2070 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning costs ($1.9 billion), escalated at rates averaging 5.6% annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive SCE contributions of approximately $100 million per year. However, SCE has requested the CPUC to authorize a reduction in the annual contributions to the decommissioning trusts beginning January 1, 2000. The plan to decommission San Onofre Unit 1 beginning in 2000, which is pending CPUC approval, is not expected to affect SCE's annual contributions to the decommissioning trusts.

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.

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 reasonable, 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 of $250/MW 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 of $250/MWh on its market for imbalance energy while a software problem affecting the efficient operation of that market persists. The caps in these markets mitigate the risk of costly price spikes that would reduce the revenue available to SCE to pay transition costs. During the upcoming year, the ISO will be considering removing these price caps, which could increase the risk of high market prices. SCE has entered into hedges against high natural gas prices, since increases in natural gas prices tend to raise the price of electricity purchased from the PX.

A 10% increase in market interest rates would result in a $7 million increase in the fair value of SCE's interest rate hedge agreements. A 10% decrease in market interest rates would result in a $7 million decline in the fair market value of interest rate hedge agreements. A 10% increase in natural gas prices would result in a $21 million increase in the fair market value of gas call options. A 10% decrease in natural gas prices would result in a $14 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.

Projected Capital Requirements

SCE's projected construction expenditures for the next five years are: 1999 — $922 million; 2000 — $831 million; 2001 — $726 million; 2002 — $699 million; and 2003 — $689 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 1999 — $401 million; 2000 — $571 million; 2001 — $646 million; 2002 — $446 million; and 2003 — $371 million.

Preferred stock redemption requirements for next five years are: 1999 through 2001 — zero; 2002 — $105 million; and 2003 — $9 million.

Regulatory Matters

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

In 1999, revenue will be determined by various mechanisms depending on the utility operation. Revenue related to distribution operations will be determined through a performance-based rate-making mechanism (PBR) and the distribution assets will have the opportunity to earn a CPUC-authorized 9.49% return. The distribution-only PBR will extend through December 2001. Transmission revenue will be determined through FERC-authorized rates and transmission assets will earn a 9.43% return. These rates are subject to refund. Key elements of PBR include: transmission and distribution (T&D) rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a bond index; standards for service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from T&D operations.

Revenue from generation-related operations will be determined through the competitive market and the CTC mechanism, which now includes the nuclear rate-making agreements. Revenue related to fossil and hydroelectric generation operations is recovered from two sources. The portion that is made uneconomic by electric industry restructuring is recovered through the CTC mechanism. The portion that is economic is recovered through the market. In 1999, fossil and hydroelectric generation assets will earn a 7.22% return.

In 1996 and 1997, the CPUC authorized revised rate-making plans for SCE's nuclear facilities, which call for the accelerated recovery of the nuclear investments 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.

The changes in revenue from the regulatory mechanisms discussed above, excluding the effects of other rate actions, are expected to have an approximately $20 million negative impact on 1999 earnings.

The CPUC is considering unbundling SCE's cost of capital based on major utility function. In May 1998, SCE filed an application on this issue and hearings were completed in October 1998. A CPUC decision is expected in early to mid-1999.

Competitive 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. The generation sector has experienced competition from nonutility power producers and regulators are restructuring California's electric utility industry.

California Electric Utility Industry Restructuring

Restructuring Decision and Statute — The CPUC's December 1995 decision on restructuring California's electric utility industry started the transition to a new market structure involving competition and customer choice. The State of California enacted legislation in 1996 to provide a transition to a competitive market structure. 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 utility-owned generation-related assets. 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 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 included a rate freeze for all other customers, including large commercial and industrial customers, as well as 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 that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the Statute 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 new market structure and customer choice began on April 1, 1998.

1998 Activities — During 1998, SCE implemented changes to comply with restructuring elements required by the CPUC and the Statute. Beginning January 1, 1998:

- SCE's rates were unbundled into separate charges for energy, transmission, distribution, the 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. 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.

- SCE 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. SCE has 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. The potential transition costs are comprised of $6.4 billion from SCE's qualifying facilities contracts, which are the direct result of prior legislative and regulatory mandates, and $4.2 billion (which reflects the sale of SCE's gas- and oil-fueled generation plants) from costs pertaining to certain generating assets 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 (as discussed in Regulatory Matters), and certain other costs.

- Residential and small commercial customers who began receiving a 10% rate reduction are repaying the rate reduction notes issued in December 1997 (see further discussion in Cash Flows from Financing Activities) through non-bypassable charges based on electricity consumption.

Effective April 1, 1998:

- The ISO assumed operational control of the transmission system after the ISO and PX had begun accepting bids and schedules for electricity purchases on March 31, 1998. The restructuring implementation costs related to the start-up and development of the PX, which are paid by the utilities, will be recovered from all retail customers over the four-year transition period. SCE's share of the charge is $45 million, plus interest and fees. SCE's share of the ISO's start-up and development costs (approximately $16 million per year) will be paid over a 10-year period.

- Customers can choose to remain utility customers with either bundled electric service or an hourly PX pricing option from SCE (which is purchasing its power through the PX), or choose direct access, which means the customer can contract directly with either independent power producers or energy service providers (ESPs) such as power brokers, marketers and aggregators. Electric utilities are continuing to provide the core distribution service of delivering energy through their distribution system regardless of a customer's choice of electricity supplier. The CPUC is continuing to regulate the prices and service obligations related to distribution services. As of December 31, 1998, approximately 47,000 of SCE's 4.3 million customers have requested the direct access option.

- Customers have options regarding metering, billing and related services (referred to as revenue cycle services) that have been provided by California's investor-owned utilities. ESPs can provide their customers with one consolidated bill for their services and the utility's services, request the utility to provide such a consolidated bill to the customer or elect to have both the ESP and the utility bill the customer for their respective charges. Customers with maximum demand above 20 kW (primarily industrial and medium and large commercial) can choose SCE or any other supplier to provide their metering service. Beginning in January 1999, all customers can make these choices. In September 1998, the CPUC issued a decision regarding the credits that would be provided to customers if they elect to obtain revenue cycle services from someone other than SCE. Although the decision adopted SCE's recommendation of using the net avoided cost, it also adopted a methodology which results in higher credits to customers but requires

ESPs to pay service fees to SCE for the costs that SCE incurs as a result of dealing with the ESP. SCE may experience a reduction in revenue security as a result of this unbundling.

During 1998, SCE sold all of its gas- and oil-fueled generation plants. The total sales price of the 12 plants was $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.

Accounting for Generation-Related Assets — If the CPUC's electric industry restructuring plan continues as described above, SCE would be allowed to recover its transition costs through non-bypassable charges to its distribution customers (although its investment in certain generation assets would be subject to a lower authorized rate of return). In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its investment in generation facilities based on new accounting guidance. The financial reporting effect of this discontinuance was to segregate these assets on the balance sheet; the new guidance did not require SCE to write off any of its generation-related assets, including related regulatory assets. However, the new guidance did not specifically address the application of asset impairment standards to these 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 CTC to distribution customers. The regulatory assets relate primarily to the recovery of accelerated income tax benefits previously flowed through to customers, purchased power 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 resulted in SCE reducing 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 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 $2.4 billion, after tax, at December 31, 1998) as a one-time, non-cash charge against earnings.

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 additional write-offs associated with these costs if they are not recovered through another regulatory mechanism. 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 10 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 reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site. Unless there is a probable amount, SCE records the lower end of this likely range of costs.

SCE's recorded estimated minimum liability to remediate its 49 identified sites is $171 million. One of SCE's sites, a former pole-treating facility, is considered a federal Superfund site and represents 41% of its recorded liability. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $247 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas- and oil-fueled power plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 41 of its sites, representing $88 million of its recorded liability, through an incentive mechanism. 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 $141 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $10 million. Recorded costs for 1998 were $7 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). The act also calls for a study to determine if additional regulations are needed to reduce regional haze in the southwestern U.S. In addition, another study is in progress to determine the specific impact of air contaminant emissions from the Mohave Coal Generating Station on visibility in Grand Canyon National Park. The potential effect of these studies on sulfur dioxide emissions regulations for Mohave is unknown.

SCE's projected environmental capital expenditures are $900 million for the 1999—2003 period, mainly for aesthetics treatment, including undergrounding certain transmission and distribution lines.

The possibility that exposure to electric and magnetic fields (EMF) emanating from power lines, household appliances and other electric sources may result in adverse health effects has been the subject of scientific research. After many years of research, scientists have not found that exposure to EMF causes disease in humans. Research on this topic is continuing. However, the CPUC has issued a decision, which provides for a rate-recoverable research and public education program conducted by California electric utilities, and authorizes these utilities to take no-cost or low-cost steps to reduce EMF in new electric facilities. SCE is unable to predict when or if the scientific community will be able to reach a consensus on any health effects of EMF, or the effect that such a consensus, if reached, could have on future electric operations.

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. However, during the Unit 2 scheduled refueling and inspection outage in 1997, an increased rate of tube degradation was identified, which resulted in the removal of more tubes from service than had been expected. 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, 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. The results of the January 1999 inspection are being analyzed to determine if there is a need for a mid-cycle inspection outage in early 2000. With the results from the January 1999 outage, 7.5% of the tubes have now been removed from service. In September 1998, San Onofre Unit 2 experienced a small amount of leakage from a steam generator tube plug, which required an 11-day outage to repair.

During Unit 3's refueling outage, which was completed in July 1997, inspections of structural supports for steam generator tubes identified several areas where the thickness of the supports had been reduced, apparently by erosion during normal plant operation. A follow-up mid-cycle inspection indicated that the erosion had been stabilized. Additional monitoring inspections are planned during the next scheduled refueling outage in 1999. To date, 5% of Unit 3's tubes have been removed from service.

During Unit 2's February 1998 mid-cycle outage, similar tube supports showed no significant levels of such erosion.

New Accounting Rules

A recently issued accounting rule requires that costs related to start-up activities be expensed as incurred, effective January 1, 1999. SCE does not expect this new accounting rule to materially affect its results of operations or financial position.

In June 1997, a new accounting standard for reporting operating segment information was issued. The new standard, which became effective for financial reports issued after December 15, 1998, requires that operating segment information be disclosed in the Notes to the Consolidated Financial Statements. Since, in management's view, SCE currently operates as one segment, this standard is not expected to affect SCE's consolidated financial statements and the accompanying notes to the consolidated financial statements.

In June 1998, a new accounting standard for derivative instruments and hedging activities was issued. The new standard, which will be effective January 1, 2000, 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

Many of SCE's existing computer systems were originally programmed to represent any date by using six digits (e.g., 12/31/99) rather than eight digits (e.g., 12/31/1999). Accordingly, such programs, if not appropriately addressed, could fail or create erroneous results when attempting to process information containing dates after December 31, 1999. This situation has been referred to generally as the Year 2000 Issue.

SCE has a comprehensive program in place to address potential Year 2000 impacts. Edison International provides overall coordination of this effort, working with SCE and its business units. SCE divides Year 2000 activities into five phases: inventory, impact assessment, remediation, testing and implementation. SCE's objective for the Year 2000 readiness of critical systems is to be 100% complete by July 1999. A critical system is defined as those applications and systems, including embedded processor technology, which if not appropriately remediated, may have a significant impact on customers, the health and safety of the public and/or personnel, the revenue stream, or regulatory compliance. SCE was 80% complete at year-end 1998 (the goal was 75%) and is on track to meets its July 1999 goal.

A system, application or physical asset is deemed to be Year 2000-ready if it is determined by SCE to be suitable for continued use through the year 2028 (or through the last year of the anticipated life of the asset, whichever occurs first), even though it is not fully Year 2000-compliant. A system, application, or physical asset is Year 2000-compliant if it accurately processes date/time data.

SCE has structured the scope of the program to focus on three principal categories: mainframe computing, distributed computing and physical assets (also known as embedded processors). The mainframe and distributed computing assets consist of computer application systems (software). Physical assets include information technology infrastructure (hardware, operating system software) and embedded processor technology in generation, transmission, distribution, and facilities components.

Year 2000-readiness preparations for SCE's mainframe financial systems were completed in the fourth quarter of 1997, and preparations for SCE's material management system were completed in the second quarter of 1998. SCE's customer information and billing system is in the process of being replaced with a system designed to be Year 2000-ready and final conversion activities are expected to be completed during the first quarter of 1999. SCE's distributed computing assets include operations and business information systems. SCE's critical operations information systems include outage management, power management, and plant monitoring and access retrieval systems. SCE's business information systems include a data acquisition system for billing, the computer call center support system, credit support and maintenance management.

Ongoing efforts in 1999 will continue to focus on guarding against reintroduction of components that are not Year 2000-ready into Year 2000-ready systems.

The other essential component of the SCE Year 2000-readiness program is to identify and assess vendor products and business partners for Year 2000 readiness, as these external parties may have the potential to impact SCE's Year 2000 readiness. SCE has implemented a process to identify and contact vendors and business partners to determine their Year 2000 status, and is evaluating the responses. As of January 31, 1999, Edison International has contacted over 4,300 critical vendors and business partners (the largest percentage of which are SCE's vendors and business partners). SCE's general policy requires that all newly purchased products and services be Year 2000-ready or otherwise designed to allow SCE to determine whether such products and services present Year 2000 issues. SCE is also working to address Year 2000 issues related to all ISO and PX interfaces, as well as joint ownership facilities. SCE exchanges Year 2000-readiness information (including, but not limited to, test results and related data) with certain of its affiliates and other external parties as part of its Year 2000-readiness efforts.

SCE's current estimate of the costs to complete these modifications, including the cost of new hardware and software application modification, is $72 million, about 40% of which is expected to be capital costs. SCE's Year 2000 costs expended through December 31, 1998, were $35 million. SCE expects current rate levels for providing electric service to be sufficient to provide funding for utility-related modifications.

Although SCE expects that its critical systems will be fully Year 2000-ready prior to year-end 1999, there can be no assurance that the systems of other companies on which the systems and operations of SCE rely will be converted on a timely basis. SCE believes that prudent business practices call for the

development of contingency plans. Such contingency plans shall include developing strategies for dealing with the most reasonably likely worst case scenario concerning Year 2000-related processing failures or malfunctions caused by SCE's internal systems or from external parties. As noted above, SCE has, in many cases, completed its Year 2000-readiness work and is currently in the remediation and testing phases for certain of their other internal systems as well as assessing risks posed by external parties. SCE is working with industry groups in an effort to help define a reasonably likely worst case scenario and in the development of contingency plans. SCE's contingency plans, which will include scheduling of key personnel, are expected to be completed by March 1999. As of January 31, 1999, draft component and system contingency plans were completed and being evaluated, draft plans were in progress for generating units, and a draft of the grid operations plan had been submitted to the Western Systems Coordinating Council. However, contingency plans will continue to be revised and enhanced as 2000 approaches. SCE also plans to test these contingency plans by conducting or participating in exercises during 1999. Also, SCE is scheduled to participate in industry-wide drills during 1999.

SCE does not expect the Year 2000 Issue to have a material adverse effect on its results of operation or financial position; however, if not effectively remediated, negative effects from Year 2000 issues, including those related to internal systems, vendors, business partners, the ISO, the PX or customers, could cause results to differ.

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, 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 effects of the Year 2000 Issue; and other unforeseen events.

Consolidated Statements of Income

In thousands Year ended December 31,	1998	1997	1996
Sales to ultimate consumers	**$7,104,800**	$7,639,417	$7,272,919
Sales to power exchange	**1,347,579**	—	—
Other	**394,719**	313,969	310,463
Operating revenue	**8,847,098**	7,953,386	7,583,382
Fuel	**323,716**	881,471	630,512
Purchased power — contracts	**2,625,900**	2,854,002	2,705,880
Purchased power — power exchange	**1,983,922**	—	—
Provisions for regulatory adjustment clauses — net	**(472,519)**	(410,935)	(225,908)
Other operating expenses	**1,480,644**	1,216,317	1,181,641
Maintenance	**410,566**	405,545	329,371
Depreciation, decommissioning and amortization	**1,545,735**	1,239,878	1,063,505
Income taxes	**445,642**	582,031	578,329
Property and other taxes	**128,402**	129,038	190,284
Net gains on sale of utility plant	**(542,608)**	(3,849)	(3,325)
Total operating expenses	**7,929,400**	6,893,498	6,450,289
Operating income	**917,698**	1,059,888	1,133,093
Provision for rate phase-in plan	**—**	(48,486)	(84,288)
Allowance for equity funds used during construction	**11,826**	7,651	15,579
Interest and dividend income	**66,725**	44,636	37,855
Other nonoperating income (deductions) — net	**(4,385)**	(23,036)	(3,623)
Total other income (deductions) — net	**74,166**	(19,235)	(34,477)
Income before interest expense	**991,864**	1,040,653	1,098,616
Interest on long-term debt	**421,857**	345,592	380,812
Other interest expense	**64,225**	101,078	73,914
Allowance for borrowed funds used during construction	**(8,046)**	(9,213)	(9,794)
Capitalized interest	**(1,294)**	(2,398)	(1,711)
Total interest expense — net	**476,742**	435,059	443,221
Net income	**515,122**	605,594	655,395
Dividends on preferred stock	**24,632**	29,488	34,395
Earnings available for common stock	**$ 490,490**	$ 576,106	$ 621,000

Consolidated Statements of Comprehensive Income

In thousands Year ended December 31,	1998	1997	1996
Net income	**$515,122**	$605,594	$655,395
Unrealized gain on securities – net	**9,275**	14,641	14,900
Reclassification adjustment for gains included in net income	**(17,836)**	—	—
Comprehensive income	**$506,561**	$620,235	$670,295

The accompanying notes are integral part of these financial statements.

Consolidated Balance Sheets

In thousands December 31,	1998	1997
ASSETS		
Transmission and distribution:		
Utility plant, at original cost, subject to cost-based rate regulation	**$11,771,678**	$11,213,352
Accumulated provision for depreciation	**(6,062,562)**	(5,573,742)
Construction work in progress	**455,233**	492,614
	6,164,349	6,132,224
Generation:		
Utility plant, at original cost, not subject to cost-based rate regulation	**1,689,469**	9,522,127
Accumulated provision for depreciation, decommissioning and amortization	**(833,917)**	(4,970,137)
Construction work in progress	**61,431**	100,283
Nuclear fuel, at amortized cost	**172,250**	154,757
	1,089,233	4,807,030
Total utility plant	**7,253,582**	10,939,254
Nonutility property — less accumulated provision for depreciation of $25,682 and $24,730 at respective dates	**56,681**	67,869
Nuclear decommissioning trusts	**2,239,929**	1,831,460
Other investments	**179,480**	171,399
Total other property and investments	**2,476,090**	2,070,728
Cash and equivalents	**81,500**	962,272
Receivables, including unbilled revenue, less allowances of $22,230 and $26,453 for uncollectible accounts at respective dates	**1,112,630**	906,388
Fuel inventory	**51,299**	58,059
Materials and supplies, at average cost	**116,259**	132,980
Accumulated deferred income taxes — net	**274,833**	123,146
Regulatory balancing accounts — net	**648,781**	193,311
Prepayments and other current assets	**91,992**	93,098
Total current assets	**2,377,294**	2,469,254
Regulatory asset — unamortized nuclear investment — net	**2,161,998**	—
Regulatory asset — income tax-related deferred charges	**1,463,256**	1,543,380
Unamortized debt issuance and reacquisition expense	**348,816**	359,304
Other deferred charges	**865,892**	677,378
Total deferred charges	**4,839,962**	2,580,062
Total assets	**$16,946,928**	$18,059,298

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

In thousands, except share amounts December 31,	1998	1997
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	**334,031**	334,031
Accumulated other comprehensive income	**39,462**	48,023
Retained earnings	**793,625**	1,407,834
	3,335,172	3,957,942
Preferred stock:		
Not subject to mandatory redemption	**128,755**	183,755
Subject to mandatory redemption	**255,700**	275,000
Long-term debt	**5,446,638**	6,144,597
Total capitalization	**9,166,265**	10,561,294
Other long-term liabilities	**467,109**	479,637
Current portion of long-term debt	**400,810**	692,875
Short-term debt	**469,565**	322,028
Accounts payable	**447,484**	406,704
Accrued taxes	**678,955**	509,270
Accrued interest	**89,828**	85,406
Dividends payable	**91,742**	95,146
Deferred unbilled revenue and other current liabilities	**1,096,332**	931,856
Total current liabilities	**3,274,716**	3,043,285
Accumulated deferred income taxes — net	**2,993,142**	2,939,471
Accumulated deferred investment tax credits	**250,116**	326,728
Customer advances and other deferred credits	**795,266**	708,745
Total deferred credits	**4,038,524**	3,974,944
Minority interest	**314**	138
Commitments and contingencies (Notes 2, 8, 9 and 10)		
Total capitalization and liabilities	**$16,946,928**	$18,059,298

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

Consolidated Statements of Cash Flows

Southern California Edison Company

In thousands Year ended December 31,	1998	1997	1996
Cash flows from operating activities:			
Net income	**$ 515,122**	$ 605,594	$ 655,395
Adjustments for non-cash items:			
Depreciation, decommissioning and amortization	**1,545,735**	1,239,878	1,063,505
Other amortization	**163,063**	81,363	90,931
Deferred income taxes and investment tax credits	**(94,504)**	63,379	46,122
Regulatory asset related to the sale of oil and gas plant	**(220,232)**	—	—
Net gains on sale of oil and gas plant	**(564,623)**	—	—
Other — net	**(78,668)**	(105,986)	5,710
Changes in working capital:			
Receivables	**(206,242)**	14,695	(9,120)
Regulatory balancing accounts	**(455,470)**	(374,799)	(156,379)
Fuel inventory, materials and supplies	**23,481**	35,707	38,791
Prepayments and other current assets	**1,106**	12,039	9,152
Accrued interest and taxes	**174,107**	16,625	(58,827)
Accounts payable and other current liabilities	**205,256**	120,464	93,362
Net cash provided by operating activities	**1,008,131**	1,708,959	1,778,642
Cash flows from financing activities:			
Long-term debt issued	—	—	396,309
Long-term debt repaid	**(776,030)**	(916,145)	(403,957)
Rate reduction notes issued	—	2,449,289	—
Rate reduction notes repaid	**(251,591)**	—	—
Preferred stock redeemed	**(74,300)**	(100,000)	—
Nuclear fuel financing — net	**16,244**	(20,140)	41,803
Short-term debt financing — net	**147,537**	91,879	(129,359)
Capital transferred	—	153,000	—
Dividends paid	**(1,129,812)**	(1,871,944)	(799,593)
Net cash used by financing activities	**(2,067,952)**	(214,061)	(894,797)
Cash flows from investing activities:			
Additions to property and plant	**(860,837)**	(685,320)	(616,427)
Proceeds from sale of oil and gas plant	**1,203,039**	—	—
Funding of nuclear decommissioning trusts	**(162,925)**	(153,756)	(148,158)
Unrealized gain (loss) in equity investments — net	**(8,561)**	14,641	14,900
Other — net	**8,333**	(28,133)	(75,985)
Net cash provided (used) by investing activities	**179,049**	(852,568)	(825,670)
Net increase (decrease) in cash and equivalents	**(880,772)**	642,330	58,175
Cash and equivalents, beginning of year	**962,272**	319,942	261,767
Cash and equivalents, end of year	**$ 81,500**	$ 962,272	$ 319,942

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

Note 1. Summary of Significant Accounting Policies

Accounting Principles

Southern California Edison Company's (SCE) accounting policies conform with generally accepted accounting principles, including the accounting principles for rate-regulated enterprises which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). As a result of industry restructuring legislation enacted by the State of California and a related change in the application of accounting principles for rate-regulated enterprises adopted by the Financial Accounting Standards Board's Emerging Issues Task Force, during the third quarter of 1997, SCE began accounting for its investment in generation facilities in accordance with accounting principles applicable to enterprises in general and SCE's balance sheets display a separate caption for its investment in generation. Application of such accounting principles to SCE's generation assets did not result in any adjustment of their carrying value; however, SCE's nuclear investments were reclassified as a regulatory asset in second quarter 1998.

Competition Transition Charge (CTC)

Beginning January 1, 1998, a non-bypassable charge is being billed to all customers, which provides SCE the opportunity to recover its costs to transition to a competitive market.

Consolidation Policy

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated.

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 electric utility restructuring, decommissioning and contingencies are further discussed in Notes 2, 9 and 10 to the Consolidated Financial Statements, respectively.

Fuel Inventory

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

Nature of Operations

SCE is a rate-regulated public utility, which produces and supplies electric energy for its 4.3 million customers in central, coastal and Southern California. SCE 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 further discussed in Note 2 to the Consolidated Financial Statements. As a result of these changes, effective April 1, 1998, SCE sells all electric energy produced to the power exchange (PX), as mandated by state legislation and purchases electric energy from the PX to supply to its customers. SCE's outstanding common stock is owned entirely by its parent company, Edison International.

Nuclear

CPUC-authorized rate phase-in plans, which deferred collection of revenue for each unit at the Palo Verde Nuclear Generating Station during the first four years of operation, ended in February 1996, September 1996 and January 1998 for Units 1, 2 and 3, respectively.

Under federal law, SCE is liable for its share of the estimated costs to decommission three federal nuclear enrichment facilities (based on purchases). These costs, which will be paid over 15 years, are recorded as a fuel cost and recovered through non-bypassable customer rates.

In 1996 and 1997, the CPUC authorized acceleration of the recovery of SCE's remaining investment of $2.6 billion in San Onofre Nuclear Generation Station Units 2 and 3 and $1.2 billion in Palo Verde Units 1, 2 and 3, respectively. 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 CTC mechanism. 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.

Reclassifications

Certain prior-year amounts were reclassified to conform to the December 31, 1998, financial statement presentation.

Regulatory Balancing Accounts

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, customers through authorized rate adjustments (with interest). On January 1, 1998, the balances in these balancing accounts were transferred to a transition cost balancing account. Also, 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 divestiture of the gas- and oil-fueled generation plants 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. For further details, see discussion under California Electric Utility Industry Restructuring in Note 2 to the Consolidated Financial Statements. Income tax effects on all balancing account changes are deferred.

In January 1997, in compliance with the restructuring legislation, overcollections in the kilowatt-hour sales and energy cost balancing accounts at December 31, 1996, were transferred to an interim balancing account and were subsequently credited to the transition cost balancing account in January 1998.

Research, Development and Demonstration (RD&D)

SCE capitalizes RD&D costs that are expected to result in plant construction. If construction does not occur, these costs are charged to expense. RD&D expenses were $2 million in 1998, $39 million in 1997 and $21 million in 1996.

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year. Beginning April 1, 1998, operating revenue also includes amounts for sales to the PX.

Supplemental Cash Flows Information

SCE's supplemental cash flows information was:

In millions Year ended December 31,	**1998**	1997	1996
Payments for interest and taxes:			
Interest — net of amounts capitalized	**$ 264**	$ 342	$ 347
Taxes	**405**	438	546

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 4.2% for 1998, 5.2% for 1997 and 4.2% for 1996.

During the third quarter of 1997, SCE discontinued accounting for its investment in generation facilities using accounting principles applicable to rate-regulated enterprises and began accounting for such investment using accounting principles applicable to enterprises in general. The carrying value of such investment was unaffected by this change. However, the nuclear investments were reclassified as a regulatory asset in second quarter 1998.

Note 2. Regulatory Matters

California Electric Utility Industry Restructuring

Restructuring Decision and Statute — The CPUC's December 1995 decision on restructuring California's electric utility industry started the transition to a new market structure involving competition and customer choice. The State of California enacted legislation in 1996 to provide a transition to a competitive market structure. 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 utility-owned generation-related assets. 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 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 included a rate freeze for all other customers, including large commercial and industrial customers, as well as 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 that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the Statute 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 new market structure and customer choice began on April 1, 1998.

1998 Activities — During 1998, SCE implemented changes to comply with restructuring elements required by the CPUC and the Statute. Beginning January 1, 1998:

- SCE's rates were unbundled into separate charges for energy, transmission, distribution, the 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. 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.

- 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. SCE has 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. The potential transition costs are comprised of $6.4 billion from SCE's qualifying facilities contracts, which are the direct result of prior legislative and regulatory mandates, and $4.2 billion (which reflects the sale of SCE's gas- and oil- fueled generation plants) from costs pertaining to certain generating assets 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.

- Residential and small commercial customers who began receiving a 10% rate reduction are repaying the rate reduction notes issued in December 1997 (see further discussion in Note 3 to the Consolidated Financial Statements) through non-bypassable charges based on electricity consumption.

Effective April 1, 1998:

- The ISO assumed operational control of the transmission system after the ISO and PX had begun accepting bids and schedules for electricity purchases on March 31, 1998. The restructuring implementation costs related to the start-up and development of the PX, which are paid by the utilities, will be recovered from all retail customers over the four-year transition period. SCE's share of the charge is $45 million, plus interest and fees. SCE's share of the ISO's start-up and development costs (approximately $16 million per year) will be paid over a 10-year period.

- Customers can choose to remain utility customers with either bundled electric service or an hourly PX pricing option from SCE (which is purchasing its power through the PX), or choose direct access, which means the customer can contract directly with either independent power producers or energy service providers (ESPs) such as power brokers, marketers and aggregators. Electric utilities are continuing to provide the core distribution service of delivering energy through their distribution system regardless of a customer's choice of electricity supplier. The CPUC is continuing to regulate the prices and service obligations related to distribution services.

- Customers have options regarding metering, billing and related services (referred to as revenue cycle services) that have been provided by California's investor-owned utilities. ESPs can provide their customers with one consolidated bill for their services and the utility's services, request the utility to provide such a consolidated bill to the customer or elect to have both the ESP and the utility bill the customer for their respective charges. Customers with maximum demand above 20kW (primarily industrial and medium and large commercial) can choose SCE or any other supplier to provide their metering service. Beginning in January 1999, all customers can make these choices. In September 1998, the CPUC issued a decision regarding the credits that would be provided to customers if they elect to obtain revenue cycle services from someone other than SCE. Although the decision adopted SCE's recommendation of using the net avoided cost, it also adopted a methodology which results in higher credits to customers but requires ESPs to pay service fees to SCE for the costs that SCE incurs as a result of dealing with the ESP.

During 1998, SCE sold all of its gas- and oil-fueled generation plants. The total sales price of the 12 plants was $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.

Accounting for Generation-Related Assets — If the CPUC's electric industry restructuring plan continues as described above, SCE would be allowed to recover its transition costs through non-bypassable charges to its distribution customers (although its investment in certain generation assets would be subject to a lower authorized rate of return). In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its investment in generation facilities based on new accounting guidance. The financial reporting effect of this discontinuance was to segregate these assets on the balance sheet; the new guidance did not require SCE to write off any of its generation-related assets, including related regulatory assets. However, the new guidance did not specifically address the application of asset impairment standards to these 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 CTC to distribution customers. The regulatory assets relate primarily to the recovery of accelerated income tax benefits previously flowed through to customers, purchased power 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 resulted in SCE reducing 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 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 $2.4 billion, after tax, at December 31, 1998) as a one-time, non-cash charge against earnings.

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 additional write-offs associated with these costs if they are not recovered through another regulatory mechanism. 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.

Note 3. Financial Instruments

Cash Equivalents

Cash and equivalents include tax-exempt investments ($78 million at December 31, 1998, and $936 million at December 31, 1997), and time deposits and other investments ($4 million at December 31, 1998, and $26 million at December 31, 1997) with maturities of three months or less.

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. 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.

SCE uses the mark-to-market accounting method for its gas call options. Gains and losses from monthly changes in market prices are recorded as income or expense. However, the 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, 1998, and December 31, 1997, 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, 1998, SCE had pledged $25 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**		1997	
		Cost Basis	**Fair Value**	Cost Basis	Fair Value
Financial assets:					
Decommissioning trusts		**$1,534**	**$2,240**	$1,371	$1,831
Equity investments		**7**	**72**	9	90
Gas call options		**39**	**31**	34	34
Financial liabilities:					
DOE decommissioning and decontamination fees		**45**	**40**	50	43
Interest rate hedges		**—**	**28**	—	24
Long-term debt		**5,447**	**5,699**	6,145	6,456
Preferred stock subject to mandatory redemption		**256**	**274**	275	293

Financial assets are carried at their fair value based on quoted market prices for decommissioning trusts and 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 financial assets were:

In millions December 31,	1998	1997
Decommissioning trusts:		
Municipal bonds	**$196**	$131
Stocks	**365**	190
U.S. government issues	**115**	91
Short-term and other	**30**	48
	706	460
Equity investments	**65**	81
Gas call options	**(8)**	—
Total	**$763**	$541

There were no unrealized holding losses on financial assets for the years presented, other than the unrealized holding loss on the gas call options in 1998.

In June 1998, a new accounting standard for derivative instruments and hedging activities was issued. The new standard, which will be effective January 1, 2000, 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.

Investments

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

All investments are classified as available-for-sale.

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: 1999 — $401 million; 2000 — $571 million; 2001 — $646 million; 2002 — $446 million; and 2003 — $371 million.

In December 1997, SCE Funding LLC, a special purpose entity (SPE), of which SCE is the sole member, issued approximately $2.5 billion of rate reduction notes to Bankers Trust Company of California, as certificate trustee for the California Infrastructure and Economic Development Bank Special Purpose Trust SCE-1 (Trust), which is a special purpose entity established by the State of California. The terms of the rate reduction notes generally mirror the terms of the pass-through certificates issued by the Trust, which are known as rate reduction certificates. The proceeds of the rate reduction notes were used by the SPE to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created pursuant to the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from a non-bypassable tariff levied on residential and small commercial customers. Notwithstanding the legal sale of the transition property by SCE to the SPE, the amounts reflected as assets on SCE's balance sheet have not been reduced by the amount of the transition property sold to the SPE, and the liabilities of the SPE for the rate reduction notes are for accounting purposes reflected as long-term liabilities on the consolidated balance sheet of SCE. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. The rate reduction notes are secured solely by the transition property and certain other assets of the SPE, and there is no recourse to SCE or Edison International.

Although the SPE is consolidated with SCE in the financial statements, as required by generally accepted accounting principles, the SPE is legally separate from SCE, the assets of the SPE 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,	**1998**	1997
First and refunding mortgage bonds:		
1999 - 2026 (5.625% to 7.5%)	**$1,550**	$1,825
Rate reduction notes:		
1999 - 2007 (6.14% to 6.42%)	**2,217**	2,463
Pollution-control bonds:		
1999 - 2027 (5.4% to 7.2% and variable)	**1,201**	1,202
Funds held by trustees	**(2)**	(2)
Debentures and notes:		
1999 - 2006 (5.6% to 8.25%)	**700**	1,195
Subordinated debentures:		
2044 (8.375%)	**100**	100
Commercial paper for nuclear fuel	**108**	92
Long-term debt due within one year	**(401)**	(693)
Unamortized debt discount — net	**(26)**	(37)
Total	**$5,447**	$6,145

Short-Term Debt

SCE has lines of credit it can use at negotiated or bank index rates. At December 31, 1998, these lines totaled $1.3 billion, with $800 million available for short-term debt and $500 million available for the long-term refinancing of certain variable-rate pollution-control debt.

Short-term debt consisted of commercial paper used to finance fuel inventories and general cash requirements. Commercial paper outstanding at December 31, 1998, and December 31, 1997, was $581 million and $415 million, respectively. 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 5.3% and 6.0% at December 31, 1998, and December 31, 1997, respectively.

Note 4. Equity

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1998, SCE had the capacity to pay $794 million in additional dividends and continue to maintain its authorized capital structure.

In 1998, SCE implemented a recently issued accounting standard that requires companies to report comprehensive income. Implementation of the new standard had no effect on SCE's results of operations or financial position.

Changes in SCE's common shareholder's equity were as follows:

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 1995	$ 2,168	$ 178	$ 18	$2,780	$5,144
Net income				655	655
Unrealized gain on securities			25		25
Tax effect			(10)		(10)
Dividends declared on common stock				(735)	(735)
Dividends declared on preferred stock				(34)	(34)
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 efffect			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

Authorized common stock is 560 million shares with no par value. 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 stocks are redeemable. Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 1999 through 2001 — zero; 2002 — $105 million; and 2003 — $9 million.

Cumulative preferred stock consisted of:

Dollars in millions, except per share amounts	December 31, 1998		1998	1997
	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
5.80	—	—	**—**	55
Total			**$129**	$184
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**	100
Total			**$256**	$275

In 1998, 193,000 shares of Series 7.23% and 2.2 million shares of Series 5.8% preferred stock were redeemed. In 1997, 4 million shares of Series 7.36% preferred stock were redeemed. There were no preferred stock issuances for the years presented.

Note 5. Income Taxes

SCE and its subsidiaries will be 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,	1998	1997
Deferred tax assets:		
Property-related	**$ 197**	$ 227
Unrealized gains or losses	**387**	273
Investment tax credits	**152**	192
Regulatory balancing accounts	**96**	180
Decommissioning-related	**126**	114
Fixed costs	**188**	109
Other	**285**	226
Total	**$1,431**	$1,321
Deferred tax liabilities:		
Property-related	**$3,005**	$3,272
Capitalized software costs	**196**	127
Regulatory balancing accounts	**162**	202
Other	**786**	536
Total	**$4,149**	$4,137
Accumulated deferred income taxes — net	**$2,718**	$2,816
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$2,993**	$2,939
Included in current assets	**275**	123

The current and deferred components of income tax expense were:

In millions Year ended December 31,	1998	1997	1996
Current:			
Federal	**$450**	$375	$386
State	**101**	100	129
	551	475	515
Deferred—federal and state:			
Accrued charges	**(43)**	(33)	(14)
Property related	**(106)**	(47)	(14)
Investment and energy tax credits — net	**(74)**	(20)	(24)
Pension reserve	**(3)**	(5)	45
Rate phase-in plan	**—**	(19)	(32)
Regulatory balancing accounts	**177**	141	34
Unbilled revenue	**(67)**	6	—
Other	**7**	22	1
	(109)	45	(4)
Total income tax expense	**$442**	$520	$511
Classification of income taxes:			
Included in operating income	**$446**	$582	$578
Included in other income	**(4)**	(62)	(67)

The composite federal and state statutory income tax rate was 40.551% for 1998 and 1997, and 41.045% for 1996.

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

Year ended December 31,	**1998**	1997	1996
Federal statutory rate	**35.0%**	35.0%	35.0%
Capitalized software	**(0.7)**	(0.9)	(0.8)
Property related and other	**11.4**	6.9	4.5
Investment and energy tax credits	**(6.8)**	(1.8)	(2.0)
State tax — net of federal deduction	**6.9**	7.0	7.1
Effective tax rate	**45.8%**	46.2%	43.8%

Note 6. Employee Compensation and Benefit Plans

Stock Option Plans

In April 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 3.0 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, 1997, was 3.8 million shares. Under the new plan, options on 1.4 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.

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 $8 million, $5 million and $8 million for the years 1998, 1997 and 1996, respectively.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma earnings of $516 million, $602 million and $653 million for the years 1998, 1997 and 1996, respectively.

The weighted-average fair value of options granted during 1998 and 1997 was $6.44 per share option and $7.62 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 1998, and December 31, 1997, was 7 years.

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:

	1998	1997
Expected life	**7 years**	7 years
Risk-free interest rate	**4.7% - 5.6%**	6.3% - 6.8%
Expected volatility	**17%**	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.

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 1996, SCE recorded pension gains from a special voluntary early retirement program. In 1998, SCE adopted a new accounting standard that revises the disclosure requirements for pension plans. Prior periods have been restated.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**1998**	1997
Change in benefit obligation		
Benefit obligation at beginning of year	**$2,094**	$2,002
Service cost	**59**	44
Interest cost	**141**	138
Actuarial loss	**90**	192
Benefits paid	**(133)**	(282)
Benefit obligation at end of year	**$2,251**	$2,094
Change in plan assets		
Fair value of plan assets at beginning of year	**$2,298**	$2,158
Actual return on plan assets	**334**	369
Employer contributions	**53**	53
Benefits paid	**(133)**	(282)
Fair value of plan assets at end of year	**$2,552**	$2,298
Funded status	**$ 301**	$ 204
Unrecognized net gain	**(372)**	(304)
Unrecognized net obligation (17-year amortization)	**33**	38
Unrecognized prior service cost	**168**	184
Pension asset (liability)	**$ 130**	$ 122
Discount rate	**6.75%**	7.0%
Rate of compensation increase	**5.0%**	5.0%
Expected return on plan assets	**7.5%**	8.0%

The components of pension expense were:

In millions Year ended December 31,	1998	1997	1996
Service cost	$ 59	$ 44	$ 49
Interest cost	141	138	178
Expected return on plan assets	(170)	(160)	(203)
Net amortization and deferral	14	13	5
Pension expense under accounting standards	44	35	29
Regulatory adjustment — deferred	11	17	22
Net pension expense recognized	55	52	51
Settlement gain	—	—	(121)
Total expense (gain)	**$ 55**	$ 52	$ (70)

Postretirement Benefits Other Than Pensions

Employees retiring at or after age 55 with at least 10 years of service (or those eligible under a 1996 special voluntary early retirement program), are eligible for postretirement health and dental care, life insurance and other benefits. In 1996, SCE recorded special termination expenses from a special voluntary early retirement program. 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,	1998	1997
Change in benefit obligation		
Benefit obligation at beginning of year	$1,533	$1,349
Service cost	41	30
Interest cost	99	99
Actuarial loss (gain)	(74)	114
Benefits paid	(54)	(59)
Benefit obligation at end of year	$1,545	$1,533
Change in plan assets		
Fair value of plan assets at beginning of year	$ 815	$ 617
Actual return on plan assets	147	147
Employer contributions	121	110
Benefits paid	(54)	(59)
Fair value of plan assets at end of year	$1,029	$ 815
Funded status	$ (516)	$ (718)
Unrecognized net loss	84	244
Unrecognized transition obligation (20-year amortization)	376	403
Recorded asset (liability)	$ (56)	$ (71)
Discount rate	6.75%	7.0%
Expected return on plan assets	7.5%	8.0%

The components of postretirement benefits other than pension expense were:

In millions Year ended December 31,	1998	1997	1996
Service cost	**$ 41**	$ 30	$ 31
Interest cost	**99**	99	90
Expected return on plan assets	**(62)**	(50)	(43)
Amortization of loss	**1**	4	6
Amortization of transition obligation	**27**	27	27
Net expense	**106**	110	111
Special termination expense	**—**	—	72
Total expense	**$ 106**	$ 110	$ 183

The assumed rate of future increases in the per-capita cost of health care benefits is 8.25% for 1999, gradually decreasing to 5.0% for 2009 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 1998, by $264 million and annual aggregate service and interest costs by $31 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 1998, by $211 million and annual aggregate service and interest costs by $24 million.

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $17 million in 1998, $15 million in 1997 and $24 in 1996.

Note 7. Jointly Owned Utility Projects

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

The investment in each project, as included in the consolidated balance sheet as of December 31, 1998, was:

In millions	Original Cost of Facility	Accumulated Depreciation and Amortization	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	$ 31	$ 6	$ 2	60%
Pacific Intertie	239	78	5	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	459	288	2	48
Mohave (coal)	315	183	6	56
Palo Verde (nuclear)[1]	1,605	908	12	16
San Onofre (nuclear)[1]	4,217	2,762	63	75
Total	$6,866	$4,225	$90	

[1] Reported as "Regulatory asset — unamortized nuclear investment — net."

Note 8. Leases

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

Estimated remaining commitments for noncancellable leases at December 31, 1998, were:

Year ended December 31,	In millions
1999	**$ 13**
2000	**11**
2001	**8**
2002	**5**
2003	**3**
Thereafter	**5**
Total	**$45**

Note 9. Commitments

Nuclear Decommissioning

Decommissioning is estimated to cost $1.9 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 plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is scheduled to begin in 2013 for San Onofre Units 2 and 3, and 2025 at Palo Verde. In December 1998, SCE requested the CPUC's approval to access its nuclear decommissioning trust funds to commence decommissioning of San Onofre Unit 1 in 2000.

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.

Decommissioning expense was $164 million in 1998, $154 million in 1997 and $148 million in 1996. The accumulated provision for decommissioning, excluding San Onofre Unit 1, was $1.2 billion at December 31, 1998, and $1.1 billion at December 31, 1997. The estimated costs to decommission San Onofre Unit 1 ($368 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 include:

In millions	Maturity Dates	December 31, 1998	1997
Municipal bonds	2000—2029	**$ 547**	$ 459
Stocks	—	**550**	392
U.S. government issues	1999—2029	**355**	357
Short-term and other	1999—2028	**82**	163
Trust fund balance (at cost)		**$1,534**	$1,371

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $63 million in 1998, $54 million in 1997 and $49 million in 1996. Proceeds from sales of securities (which are reinvested) were $1.2 billion in 1998, $595 million in 1997 and $1.0 billion in 1996. Approximately 89% 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.

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.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is not expected to provide more than 5% of current or estimated future operating capacity. SCE's minimum commitment under both contracts is approximately $172 million through 2017.

Certain commitments for the years 1999 through 2003 are estimated below:

In millions	1999	2000	2001	2002	2003
Projected construction expenditures	$922	$831	$726	$699	$689
Fuel supply contracts	167	136	123	139	117
Purchased-power capacity payments	744	786	797	704	689
Unconditional purchase obligations	9	10	10	9	10

Note 10. Contingencies

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

Environmental Protection

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

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

SCE's recorded estimated minimum liability to remediate its 49 identified sites is $171 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 $247 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE

among a range of reasonably possible outcomes. SCE has sold all of its gas- 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 41 of its sites, representing $88 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 $141 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 $4 million to $10 million. Recorded costs for 1998 were $7 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 $9.6 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 primarily by mutual insurance companies 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 $22 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. The Act requires that the DOE provide for the disposal of spent nuclear fuel and high-level radioactive waste from nuclear generation stations beginning January 31, 1998. However, the DOE did not meet its obligations. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or from other nuclear power plants.

SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

SCE 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 could require new and separate interim storage facilities, the costs for which have not been determined. Extended delays by the DOE can lead to consideration of costly alternatives involving siting and environmental issues.

Palo Verde on-site spent fuel storage capacity will accommodate needs until 2002 for Units 1 and 2, and until 2003 for Unit 3. Arizona Public Services, operating agent for Palo Verde, has commenced construction of an interim fuel storage facility and projects completion 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, through other court actions.

Quarterly Financial Data

	1998					1997				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue[1]	$8,847	$2,245	$3,057	$1,922	$1,623	$7,953	$1,980	$2,434	$1,844	$1,695
Operating income	918	241	237	212	228	1,060	248	349	229	234
Net income	515	121	169	120	105	606	123	233	129	121
Earnings available for common stock	490	115	163	114	98	576	116	226	122	112
Common dividends declared	1,101	141	422	442	96	1,829	1,266	217	171	175

(1) Effective second quarter 1998, operating revenue includes sales to the PX.

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 generally accepted accounting principles applied on a consistent basis 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 generally accepted auditing standards 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.

Richard K. Bushey
Vice President
and Controller

John E. Bryson
Chairman of the Board
and Chief Executive Officer

February 4, 1999

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, 1998, and 1997, and the related consolidated statements of income, comprehensive income and cash flows for each of the three years in the period ended December 31, 1998. 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 generally accepted auditing standards. 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 o. SCE and its subsidiaries as of December 31, 1998, and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Los Angeles, California
February 4, 1999

Selected Financial and Operating Data: 1994-1998

Southern California Edison Company

Dollars in millions	1998	1997	1996	1995	1994
Income statement data:					
Operating revenue[1]	**$ 8,847**	$ 7,953	$ 7,583	$ 7,873	$ 7,799
Operating expenses[2]	**7,929**	6,893	6,450	6,724	6,705
Fuel and purchased power expenses[2]	**4,934**	3,735	3,336	3,197	3,403
Income tax from operations	**446**	582	578	560	508
Allowance for funds used during construction	**20**	17	25	34	29
Interest expense — net	**485**	444	453	464	443
Net income	**515**	606	655	680	639
Earnings available for common stock	**490**	576	621	643	599
Ratio of earnings to fixed charges	**2.95**	3.49	3.54	3.52	3.43
Balance sheet data:					
Assets	**$16,947**	$18,059	$17,737	$18,155	$18,076
Gross utility plant	**14,150**	21,483	21,134	20,717	20,127
Accumulated provision for depreciation and decommissioning	**6,896**	10,544	9,431	8,569	7,710
Common shareholder's equity	**3,335**	3,958	5,045	5,144	5,039
Preferred stock:					
Not subject to mandatory redemption	**129**	184	284	284	359
Subject to mandatory redemption	**256**	275	275	275	275
Long-term debt	**5,447**	6,145	4,779	5,215	4,988
Capital structure:					
Common shareholder's equity	**36.4%**	37.5%	48.6%	47.1%	47.3%
Preferred stock:					
Not subject to mandatory redemption	**1.4%**	1.7%	2.7%	2.6%	3.3%
Subject to mandatory redemption	**2.8%**	2.6%	2.7%	2.5%	2.6%
Long-term debt	**59.4%**	58.2%	46.0%	47.8%	46.8%
Operating data:					
Peak demand in megawatts (MW)	**19,935**	19,118	18,207	17,548	18,044
Generation capacity at peak (MW)	**10,546**	21,511	21,602	21,603	20,615
Kilowatt-hour sales (kWh) (in millions)	**76,595**	77,234	75,572	74,296	77,986
Total energy requirement (kWh) (in millions)[3]	**80,289**	86,849	84,236	81,924	85,011
Energy mix:					
Thermal	**38.8%**	44.6%	47.6%	51.6%	59.5%
Hydro	**7.4%**	6.5%	6.9%	7.7%	3.9%
Purchased power and other sources	**53.8%**	48.9%	45.5%	40.7%	36.6%
Customers (in millions)	**4.27**	4.25	4.22	4.18	4.15
Full-time employees	**13,177**	12,642	12,057	14,886	16,351

(1) 1998 includes $1.3 billion from sales to the power exchange (PX).
(2) 1998 includes $2.0 billion for purchases from the PX.
(3) 1998 excludes direct access and resale customer requirements.

Board of Directors

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Chairman of the Board and CEO,
Edison International and SCE

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
President and Chief Operating
Officer, SCE

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

Carl F. Huntsinger
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DAE Limited Partnership Ltd.,
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Charles D. Miller
Chairman of the Board,
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Managing Director,
Smith and Crowley Incorporated,
Pasadena, California

Thomas C. Sutton
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Pacific Life Insurance Company,
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President, Joint Oceanographic
Institutions, Inc., and
President, Consortium for
Oceanographic Research and Education,
Washington, D.C.

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

* Retiring on April 15, 1999

Management Team

John E. Bryson
Chairman of the Board and CEO

Stephen E. Frank
President and Chief Operating Officer

Bryant C. Danner
Executive Vice President and
General Counsel

Alan J. Fohrer
Executive Vice President and
Chief Financial Officer

Harold B. Ray
Executive Vice President,
Generation Business Unit

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

Theodore F. Craver, Jr.
Senior Vice President and Treasurer

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,
T&D Business Unit

Emiko Banfield
Vice President, Shared Services

Richard K. Bushey**
Vice President and Controller

Bruce C. Foster
Vice President,
San Francisco Regulatory Affairs

Lawrence D. Hamlin
Vice President, Power Production

Thomas J. Higgins
Vice President,
Corporate Communications

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

Frank J. Quevedo
Vice President, Equal Opportunity

Anthony L. Smith***
Vice President, Tax

Mahvash Yazdi
Vice President and Chief
Information Officer

Beverly P. Ryder
Corporate Secretary

** Resigned March 1, 1999
*** Effective March 1, 1999

Shareholder Information

Annual Meeting of Shareholders

Thursday, April 15, 1999
10:00 a.m.
The Industry Hills Sheraton Resort and Conference Center
One Industry Hills Parkway
City of Industry, California

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

Southern California Edison Company maintains shareholder records and is transfer agent and registrar for SCE preferred stock. Shareholders may call Shareholder Services, (800) 347-8625, between 8:00 a.m. and 4:00 p.m. (Pacific 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
- request access to online account information via Edison International's Internet Home Page, www.edisoninvestor.com

The address of Shareholder Services is:

P.O. Box 400, Rosemead, California 91770-0400
FAX: (626) 302-4815

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