Selected Financial and Operating Data: 1992-1996

Southern California Edison Company

Dollars in millions	1996	1995	1994	1993	1992
Income statement data:					
Operating revenue	$ 7,583	$ 7,873	$ 7,799	$ 7,397	$ 7,722
Operating expenses	6,450	6,724	6,705	6,232	6,492
Fuel and purchased power expenses	3,336	3,197	3,403	3,290	3,086
Income tax from operations	578	560	508	506	520
Allowance for funds used during construction	25	34	29	36	37
Interest expense—net	453	464	443	449	517
Net income	655	680	639	678	673
Earnings available for common stock	621	643	599	637	631
Ratio of earnings to fixed charges	3.54	3.52	3.43	3.39	3.16
Balance sheet data:					
Assets	$17,737	$18,155	$18,076	$18,098	$15,969
Gross utility plant	21,134	20,717	20,127	19,441	18,652
Accumulated provision for depreciation and decommissioning	9,431	8,569	7,710	7,138	6,544
Common shareholder's equity	5,045	5,144	5,039	4,932	4,775
Preferred stock:					
Not subject to mandatory redemption	284	284	359	359	359
Subject to mandatory redemption	275	275	275	275	278
Long-term debt	4,779	5,215	4,988	5,234	5,184
Capital structure:					
Common shareholder's equity	48.6%	47.1%	47.3%	45.7%	45.1%
Preferred stock:					
Not subject to mandatory redemption	2.7%	2.6%	3.3%	3.3%	3.4%
Subject to mandatory redemption	2.7%	2.5%	2.6%	2.5%	2.6%
Long-term debt	46.0%	47.8%	46.8%	48.5%	48.9%
Operating data:					
Peak demand in megawatts (MW)	18,207	17,548	18,044	16,475	18,413
Generation capacity at peak (MW)	21,602	21,603	20,615	20,606	20,712
Kilowatt-hour sales (kWh) (in millions)	75,572	74,296	77,986	73,308	74,186
Average annual kWh sales per residential customer	6,322	6,188	6,259	6,070	6,311
Total energy requirement (kWh) (in millions)	84,236	81,924	85,011	81,328	82,199
Energy mix:					
Thermal	47.6%	51.6%	59.5%	53.8%	59.8%
Hydro	6.9%	7.7%	3.9%	7.3%	3.4%
Purchased power and other sources	45.5%	40.7%	36.6%	38.9%	36.8%
Customers (in millions)	4.22	4.18	4.15	4.12	4.11
Full-time employees*	12,057	14,886	16,351	16,585	16,922

*1992-1994 are based on twelve-month averages.

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

In the following 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 the outcome of state and federal regulatory proceedings affecting the restructuring of the electric utility industry, the impacts of new laws and regulations relating to restructuring and other matters, the effects of increased competition in the electric utility business, and changes in prices of electricity and costs for fuel.

Results of Operations

Earnings

Southern California Edison Company's (SCE) 1996 earnings were $621 million, compared with $643 million in 1995 and $599 million in 1994. Included in earnings are special charges of $18 million in 1996, $15 million in 1995 and $18 million in 1994, primarily related to workforce management costs. Excluding special charges, SCE's 1996 earnings decreased $19 million over 1995. The decreased earnings are primarily attributable to a reduction in authorized rates of return and operating expenses, partially offset by improved operating performance. Excluding special charges, SCE's 1995 earnings increased $41 million over 1994, primarily due to a higher authorized return on common equity for 1995, partially offset by the financial effect of the 1995 general rate case settlement.

Operating Revenue

Operating revenue decreased 4% from 1995, as increased sales volume was offset by lower average rates. The lower rates are attributable to the California Public Utilities Commission's (CPUC) decision to lower SCE's 1996 authorized revenue by 4.4%. Additionally, during 1996 SCE issued a one-time bill credit of $237 million to ratepayers as part of a CPUC-ordered refund of energy-cost balancing account overcollections. Operating revenue in 1995 increased slightly over 1994, mainly due to a 2.6% CPUC-authorized rate increase, partially offset by a decrease in sales volume to resale cities and milder weather in 1995. In 1996, over 98% of operating revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

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

The changes in operating revenue resulted from:

In millions Year ended December 31,	1996	1995	1994
Operating revenue—			
Rate changes	$ (522)	$ 168	$ 112
Sales volume changes	206	(129)	308
Other	26	35	(18)
Total	$ (290)	$ 74	$ 402

In March 1995, SCE announced its intention to freeze average rates for residential, small business and agricultural customers through 1996, and announced a five-year goal to reduce system average rates by 25% on an inflation-adjusted basis (from 10.7¢ per kilowatt-hour to below 10¢ per kilowatt-hour). In February 1996, the CPUC approved a system-wide rate reduction which will drop the average price per kilowatt-hour from 10.7¢ to 10.1¢. Legislation enacted in September 1996 provides for, among other things, at least a 10% rate reduction for residential and small commercial customers beginning in 1998 (see discussion under Competitive Environment).

Operating Expenses

Fuel expense increased slightly in 1996 due to higher gas prices and changes in the fuel mix. Fuel expense decreased 27% in 1995 from 1994, since hydro generation was up significantly in 1995 due to greater rainfall, resulting in lower gas purchases. In addition, the San Onofre Nuclear Generating Station units were out of service a total of five months in 1995 for refueling and maintenance, causing a decrease in nuclear fuel expense. Lower overall gas prices in 1995 also contributed to the decrease in energy costs.

Purchased-power expense increased slightly in 1996 and 1995, due to an increase in power purchased under federally mandated contracts. SCE is required under federal law to purchase power from certain nonutility generators even though energy prices under these contracts are generally higher than other sources. In 1996, SCE paid about $1.7 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 substantially in 1996, compared to 1995. The decrease is mainly due to the energy-cost balancing account-related refund as discussed above, lower base rate revenue and undercollections related to the accelerated recovery of SCE's remaining investment in San Onofre Units 2 and 3 (see discussion in Note 1 to the Consolidated Financial Statements). The provisions increased in 1995, as CPUC-authorized fuel and purchased-power cost estimates exceeded actual energy costs. Actual energy costs were lower than estimated in 1995, due to the increase in hydro generation and lower gas prices.

Other operating expenses declined in both 1996 and 1995, due to ongoing cost reduction efforts and improved operating performance.

Maintenance expense decreased 8% in 1996, due to lower overall costs at SCE's generation, transmission and distribution operating facilities. Maintenance expense increased 8% in 1995, due to higher expenses related to the scheduled refueling and maintenance outages at San Onofre Units 2 and 3.

Depreciation and decommissioning expense increased 12% in 1996. The change is due to higher depreciation rates and the accelerated recovery of San Onofre Units 2 and 3.

Income taxes increased slightly during 1996, mainly due to an increase in deferred taxes resulting from the accelerated recovery of San Onofre Units 2 and 3.

Other Income and Deductions

The provision for rate phase-in plan reflects 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 Nuclear Generating Station. The deferred revenue (including interest) is being collected evenly over the final six years of each unit's plan. The plan ended in February 1996 and September 1996 for Units 1 and 2, respectively. The plan ends in January 1998 for Unit 3. The provision is a non-cash offset to the collection of deferred revenue.

Other nonoperating income decreased substantially in 1996, compared to 1995, primarily due to additional accruals for regulatory matters. Other nonoperating income decreased in 1995, as CPUC-authorized incentive awards were below 1994 levels.

Interest Expense

Other interest expense decreased in 1996, due to the lower levels of short-term debt and lower interest rates. Other interest expense increased 30% in 1995, due to higher interest rates and higher balances in the regulatory balancing accounts.

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.

In June 1994, SCE lowered its quarterly common stock dividend to its parent, Edison International, by 30%, due to the uncertainty of future earnings levels arising from the changing nature of California's electric utility regulation.

Currently, Edison International has authorized the repurchase of up to $800 million of its common stock. Edison International has repurchased 27.4 million shares ($497 million) through January 31, 1997, funded by dividends from its subsidiaries and its lines of credit. As excess cash becomes available, SCE intends to pay cash dividends to Edison International, while maintaining its CPUC-authorized capital structure.

SCE's cash flow coverage of dividends during 1996 decreased to 2.2 times from 3.5 times in 1995 and 3.1 times in 1994, due to the additional cash needs of Edison International for debt repayment and other cash needs.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $1.8 billion in 1996, $2.0 billion in 1995 and $1.8 billion in 1994. Cash from operations exceeded capital requirements for all years presented.

Cash Flows from Financing Activities

Short-term debt is used to finance fuel inventories, balancing account undercollections 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 its articles of incorporation and trust indenture. As of December 31, 1996, SCE could issue approximately $7.9 billion of additional first and refunding mortgage bonds and $4.5 billion of preferred stock at current interest and dividend rates.

At December 31, 1996, SCE had available lines of credit of $1.1 billion, with $600 million for 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 with various expiration dates; the majority have five-year terms.

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, 1996, SCE had the capacity to pay $112 million in additional dividends and continue to maintain its authorized capital structure.

Cash Flows from Investing Activities

The primary uses of cash for investing activities are additions to property and plant and funding of nuclear decommissioning trusts. Decommissioning costs are accrued and recovered in rates over the term of each nuclear generating facility's operating license through charges to depreciation expense. SCE estimates that it will spend approximately $12.7 billion between 2013-2070 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning costs ($2.0 billion), escalated using a 6.65% annual rate. These costs are expected to be funded from independent decommissioning trusts which receive SCE contributions of approximately $100 million per year until decommissioning begins.

Projected Capital Requirements

SCE's projected construction expenditures for the next five years are: 1997--$802 million; 1998--$636 million; 1999--$664 million; 2000--$647 million; and 2001--$650 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 1997--$501 million; 1998-$447 million; 1999--$155 million; 2000--$325 million; and 2001--$400 million.

Regulatory Matters

SCE's 1997 CPUC-authorized rates remain unchanged from 1996 levels due to the recently enacted legislation which requires that system average rates remain frozen at the June 10, 1996, level of 10.1¢ per kilowatt-hour (see discussion in Competitive Environment).

The CPUC's 1997 cost-of-capital decision authorized an 11.6% return on common equity and a 48% common equity ratio, both unchanged from 1996 levels. SCE's return on rate base was lowered from 9.55% to 9.49%. The decision, excluding the effects of other rate actions, would reduce 1997 earnings by approximately $5 million.

A 1994 CPUC decision stated that SCE was liable for expenditures related to a 1985 accident at the Mohave Generating Station. In July 1996, the CPUC approved a settlement agreement between SCE and the Office of Ratepayer Advocates (ORA) which resulted in a $39 million (including interest) refund to SCE's customers. The refund, which had been previously reserved, was completed by year-end 1996.

In May 1994, SCE filed its testimony in the non-Qualifying Facilities phase of the 1994 Energy Cost Adjustment Clause proceeding. In May 1995, the ORA filed its report on the reasonableness of SCE's gas supply costs for both the 1993 and 1994 record periods. The report recommends a disallowance of $13.3 million for excessive costs incurred from November 1993 through March 1994 associated with SCE's Canadian gas purchase and supply contracts. The report requests that the CPUC defer finding SCE's Canadian supply and transportation agreements reasonable for the duration of their terms and that the costs under these contracts be reviewed on a yearly basis. In October 1996, the ORA issued its report for the 1995 record period recommending a $37.6 million disallowance for excessive costs incurred from April 1994 through March 1995. Both proposed disallowances have been consolidated into one proceeding. SCE and the ORA have filed several rounds of testimony on this issue. Hearings began in January 1997 and are expected to conclude in February 1997. A decision is expected in late 1997.

On December 23, 1996, the CPUC issued a final decision on SCE's proposal for a new rate mechanism for its 15.8% share of the three units at Palo Verde. The decision adopts the Palo Verde All-Party Settlement filed with the CPUC on November 15, 1996. The settlement was based on a Memorandum of Understanding signed by all of the active parties to the Palo Verde proceeding. Under the settlement, SCE has the opportunity to recover its remaining investment (approximately $1.2 billion) in Palo Verde beginning January 1, 1997, and ending December 31, 2001, earning a reduced rate of return on rate base of 7.35% instead of the current 9.49%. Also, SCE will utilize a balancing account to pass through Palo Verde's incremental operating costs (considered reasonable as long as they do not exceed 30% of a baseline forecast and the site's gross annual capacity factor does not go below 55%) to ratepayers. Beginning January 1, 1998, this balancing account will become part of the competition transition charge (CTC) mechanism. If SCE's actual costs are less than the forecast, the difference will benefit ratepayers as a credit to the CTC mechanism. The 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. After 2001, SCE's ratepayers will receive 50% of the benefits derived from the operation of Palo Verde. The decision is projected to reduce SCE's 1997 earnings by approximately $21 million.

Competitive Environment

SCE currently operates in a highly regulated environment in which it has an obligation to provide 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.

On September 23, 1996, the State of California enacted legislation to provide a transition to a competitive market structure. The legislation substantially adopts the CPUC's December 1995 restructuring decision (discussed below) by addressing stranded-cost recovery for utilities, 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 would be recovered through the terms of their contracts while most of the remaining transition costs would be recovered through 2001. The legislation also includes provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, thereby allowing SCE to give a rate reduction of at least 10% to these customers, beginning January 1, 1998. The financing would occur with securities issued by the California Infrastructure and Economic Development Bank, or an entity approved by the Bank. The legislation includes 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 based on cost-of-service regulation during the 1998-2001 transition period. In addition, the legislation mandates the implementation of a

non-bypassable CTC that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the legislation contains provisions for the recovery (through 2006) of reasonable employee-related transition costs incurred and projected for retraining, severance, early retirement, outplacement and related expenses for utility workers. In light of the legislation, the CPUC is reassessing the need to prepare an environmental impact report.

In December 1995, the CPUC issued its decision on restructuring California's electric utility industry. The transition to a new market structure, which is expected to provide competition and customer choice, would begin January 1, 1998, with all consumers participating by 2003 (changed to 2002 by the recently enacted legislation). Key elements of the CPUC decision include:

- Creation of an independent power exchange (PX) to manage electric supply and demand. California's investor-owned utilities would be required to purchase from and sell to the exchange all of their power during the transition period, while other generators could voluntarily participate.

- Creation of an independent system operator (ISO) to have operational control of the utilities' transmission facilities and, therefore, control the scheduling and dispatch of all electricity on the state's power grid.

- Availability of customer choice through time-of-use rates, direct customer access to generation providers with transmission arrangements through the system operator, and customer-arranged "contracts for differences" to manage price fluctuations from the PX.

- Recovery of costs to transition to a competitive market (utility investments, obligations incurred to serve customers under the existing framework and reasonable employee-related costs) through a non-bypassable charge, applied to all customers, called the CTC.

- CPUC-established incentives to encourage voluntary divestiture (through spin-off or sale to an unaffiliated entity) of at least 50% of utilities' gas-fueled generation to address market power issues.

- Performance-based ratemaking (PBR) for those utility services not subject to competition.

In April 1996, SCE, Pacific Gas & Electric Company and San Diego Gas & Electric Company filed a proposal with the FERC regarding the creation of the PX and the ISO. On November 26, 1996, the FERC conditionally accepted the proposal and directed the three utilities to file more specific information by March 31, 1997. In July 1996, the three utilities jointly filed an application with the CPUC requesting approval to establish a restructuring trust which would obtain loans up to $250 million for the development of the ISO and PX through January 1, 1998. The loans would be backed by utility guarantees; SCE's share would be 45%. Once the ISO and PX are formed, they will repay the trust's loans and recover funds from future ISO and PX customers. In August 1996, the CPUC issued an interim order establishing the restructuring trust and the funding level of $250 million which will be used to build the hardware and software systems for the ISO and PX.

Recovery of costs to transition to a competitive market would be implemented through a non-bypassable CTC. This charge would apply to all customers who were using or began using utility services on or after the December 20, 1995, decision date. In August 1996, in compliance with the CPUC's restructuring decision, SCE filed its application to estimate its 1998 transition costs. In October 1996, SCE amended its transition cost filing to reflect the effects of the legislation enacted in September 1996. Under the rate freeze codified in the legislation, the CTC will be determined residually (i.e., after subtracting other cost components for the PX, transmission and distribution (T&D), nuclear decommissioning and public benefit programs). Nevertheless, the CPUC directed that the amended application provide estimates of SCE's potential transition costs from 1998 through 2030. SCE provided two estimates between approximately $13.1 billion (1998 net present value), assuming the fossil plants have a market value equal to their net book value, and $13.8 billion (1998 net present value), assuming the fossil plants have no market value. These estimates are based on incurred costs, and 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:

$7.5 billion from SCE's qualifying facility contracts, which are the direct result of legislative and regulatory mandates; and $5.6 billion to $6.3 billion from costs pertaining to certain generating plants and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed-through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre (as discussed in Note 1 to the Consolidated Financial Statements) and Palo Verde, nuclear decommissioning and certain other costs.

On November 27, 1996, SCE filed an application with the CPUC to voluntarily divest, by auction, all of its oil- and gas-fueled generation assets. This application builds on SCE's March 1996 plan which outlined how SCE proposed to divest 50% of these assets. Under the new proposal, SCE would continue to operate and maintain the divested power plants for at least two years following their sale, as mandated by the recent restructuring legislation. In addition, SCE would offer workforce transition programs to those employees who may be impacted by divestiture-related job reductions. SCE's proposal is contingent on the overall electric industry restructuring implementation process continuing on a satisfactory path. CPUC approval of the oil- and gas-fueled generation divestiture was requested for late 1997.

In September 1996, the CPUC adopted a non-generation T&D PBR mechanism for SCE which began on January 1, 1997. According to the CPUC decision, beginning in 1998, the transmission portion is to be separated from non-generation PBR and subject to ratemaking under the rules of the FERC. The distribution-only PBR will extend through December 2001. Key elements of the non-generation PBR include: T&D rates indexed for inflation based on the Consumer Price Index less a productivity factor; elimination of the kilowatt-hour sales adjustment; 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. In July 1996, SCE filed a PBR proposal for its hydroelectric plants and a proposed structure for performance-based local reliability contracts for certain fossil-fueled plants. If approved, the hydro PBR would be in effect for three years and the initial terms of the local reliability contracts, which are subject to FERC approval, would be in effect for up to three years, both beginning January 1, 1998. A final CPUC decision on hydro PBR is expected by year-end 1997.

In July 1996, SCE filed a proposal with the CPUC related to the conceptual aspects of separating the costs associated with generation, transmission, distribution, public benefit programs and the CTC. The filing was in response to CPUC and FERC directives which require electric services, such as T&D, to be functionally separate and available to all customers on a nondiscriminatory basis without cost-shifting among customers. On December 6, 1996, SCE filed a more comprehensive plan for the functional unbundling of SCE's rates for electric service, beginning on January 1, 1998. In response to CPUC and FERC orders, as well as the new restructuring legislation, this filing addressed the implementation-level detail for the functional unbundling of rates in separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The filing also included proposals for establishing new regulatory proceedings to replace current proceedings that will no longer be necessary during the rate freeze period.

Although depreciation-related differences could result from applying a regulatory prescribed depreciation method (straight-line, remaining-life method) rather than a method that would have been applied absent the regulatory process, SCE believes that the depreciable lives of its generation-related assets would not vary significantly from that of an unregulated enterprise, as the CPUC bases depreciable lives on periodic studies that reflect the physical useful lives of the assets. SCE also believes that any depreciation-related differences would be recovered through the CTC.

If events occur during the restructuring process that result in all or a portion of the CTC being improbable of recovery, SCE could have 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 implementation phases, or the effect, after the transition period, that competition will have on its results of operations or financial position.

Subsequent Event

If the CPUC's restructuring is implemented as outlined, SCE would be allowed to recover its CTC (subject to a lower return on equity) and believes it should be allowed to continue to apply accounting standards that recognize the economic effects of rate regulation for its generation-related assets during the 1998-2001 transition period. However, in response to a request by the staff of the Securities and Exchange Commission (SEC), in December 1996, SCE submitted its views on the continued applicability of regulatory accounting standards for its generation-related assets. In its submittal, SCE and its independent accountants jointly concluded that, based on their current analysis, SCE will continue to meet the criteria for applying these accounting standards through the 1998-2001 transition period. In its February 1997 response, the SEC staff expressed continuing concern with SCE's conclusion and indicated that they wanted to meet further with SCE and the other major California electric utilities to resolve this matter. SCE and its independent accountants continue to believe that SCE meets such criteria and plan to meet with the SEC staff to present additional and clarifying information seeking to convince the SEC staff of the merits of SCE's position. The authority to require SCE to discontinue applying regulatory accounting standards rests with the SEC. If SCE is required to discontinue the application of these accounting standards for its generation-related assets, it would have to write off generation-related regulatory assets, which at December 31, 1996, totaled approximately $600 million on an after-tax basis, primarily for the recovery of income tax benefits previously flowed-through to customers, the Palo Verde phase-in plan and unamortized loss on reacquired debt.

SCE believes that a proper application of regulatory accounting standards will result in it no longer meeting the criteria to apply these accounting standards to all of its non-hydroelectric generation-related assets after the end of the 1998-2001 transition period. If SCE continues the application of these accounting standards during the transition period, but during the transition period events occur that result in SCE no longer meeting the criteria for applying such standards, SCE may be required to write off the remaining balance of its recorded generation-related regulatory assets existing at that time.

If a non-cash write-off is required, SCE believes that it should not affect the stranded-cost recovery plans set forth in the CPUC's December 1995 restructuring decision and legislation enacted by the State of California in September 1996.

FERC Stranded Cost/Open Access Transmission Decision

In April 1996, the FERC issued its decision on stranded cost recovery and open access transmission, effective July 1996. The decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with increased access to transmission facilities for wholesale transactions and also establishes information requirements for the transmission utility. The decision also provides utilities with the recovery of stranded costs, which are prior-service costs incurred under the current regulatory framework. In addition to providing recovery of stranded costs associated with existing wholesale customers, the FERC directed that it would have primary jurisdiction over the recovery of stranded costs associated with retail-turned-wholesale customers, such as the formation of a new municipal electric system. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states and the FERC would only address recovery of these costs if the state has no authority to do so. In compliance with the April 1996 FERC decision, SCE filed a revised open access tariff with the FERC in July 1996. The tariff became effective on an interim basis, subject to refund, as of its filing date. Several wholesale customers have filed protests with the FERC on the transmission rate levels, and a ruling from the FERC setting the rates to be decided at formal hearings is anticipated in early 1997.

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 55 identified sites was $114 million at December 31, 1996. One of SCE's sites, a former pole-treating facility, is considered a federal Superfund site and represents 71% 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 $211 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental-cleanup costs at 35 of its sites, representing $101 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 a number of its carriers. Costs incurred at the remaining 20 sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $104 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 $8 million. Recorded costs for 1996 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 have a material adverse effect on 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 capital expenditures to protect the environment are $900 million for the 1997-2001 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 is receiving increased attention. The scientific community has not yet reached a consensus on the nature of any health effects of EMF. 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.

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

Palo Verde Steam Tube Rupture

In 1993, a steam generator tube ruptured at Palo Verde Unit 2; additional cracking was found in other tubes. Arizona Public Service Company (APS), the operating agent for Palo Verde, has taken, and will continue to

take, remedial actions that it believes have slowed the rate of steam generator tube degradation in all three units. APS believes that the steam generators in only one of the units will have to be replaced within five to ten years. Based on APS' 100% share estimate, SCE estimates its share of the costs to be between $22 million and $24 million, plus replacement power costs. SCE is evaluating APS' analyses, conducting its own review, and has not yet decided whether it supports replacement of the steam generators.

Workforce Reductions

During 1996, SCE offered a voluntary retirement program to certain eligible employees. Approximately 3,000 employees (2,200 non-represented and 800 represented employees) accepted the terms of this program. After allowance for the effects of pension settlement gains, SCE's net expense for this program was $4 million.

Proposed New Accounting Standard

During 1996, the Financial Accounting Standards Board issued an exposure draft that would establish accounting standards for the recognition and measurement of closure and removal obligations. The exposure draft would require the estimated present value of an obligation to be recorded as a liability, along with a corresponding increase in the plant or regulatory asset accounts when the obligation is incurred. If the exposure draft is approved in its present form, it would affect SCE's accounting practices for the decommissioning of its nuclear power plants, obligations for coal mine reclamation costs and any other activities related to the closure or removal of long-lived assets. SCE does not expect that the accounting changes proposed in the exposure draft would have an adverse effect on its results of operations even after deregulation due to its current and expected future ability to recover these costs through customer rates.

Consolidated Statements of Income

Southern California Edison Company

In thousands Year ended December 31,	1996	1995	1994
Operating revenue	$7,583,382	$ 7,872,718	$ 7,798,601
Fuel	630,512	614,954	840,607
Purchased power	2,705,880	2,581,878	2,562,890
Provisions for regulatory adjustment clauses—net	(225,908)	229,744	54,772
Other operating expenses	1,178,316	1,226,534	1,315,249
Maintenance	329,371	356,693	330,161
Depreciation and decommissioning	1,063,505	954,141	890,656
Income taxes	578,329	559,694	507,626
Property and other taxes	190,284	200,236	202,711
Total operating expenses	6,450,289	6,723,874	6,704,672
Operating income	1,133,093	1,148,844	1,093,929
Provision for rate phase-in plan	(84,288)	(122,233)	(136,596)
Allowance for equity funds used during construction	15,579	19,082	14,348
Interest income	37,855	37,644	31,082
Other nonoperating income—net	(3,623)	45,651	64,597
Total other income (deductions)—net	(34,477)	(19,856)	(26,569)
Income before interest expense	1,098,616	1,128,988	1,067,360
Interest on long-term debt	380,812	385,187	381,827
Other interest expense	73,914	80,130	61,646
Allowance for borrowed funds used during construction	(9,794)	(14,489)	(14,440)
Capitalized interest	(1,711)	(1,531)	(254)
Total interest expense—net	443,221	449,297	428,779
Net income	655,395	679,691	638,581
Dividends on preferred stock	34,395	36,764	40,080
Earnings available for common stock	$ 621,000	$ 642,927	$ 598,501

Consolidated Statements of Retained Earnings

In thousands Year ended December 31,	1996	1995	1994
Balance at beginning of year	$2,780,058	$ 2,683,568	$ 2,586,890
Net income	655,395	679,691	638,581
Dividends declared on common stock	(735,429)	(545,672)	(501,823)
Dividends declared on preferred stock	(34,395)	(36,764)	(40,080)
Reacquired capital stock expense	(17)	(765)	-
Balance at end of year	$2,665,612	$ 2,780,058	$ 2,683,568

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

Consolidated Balance Sheets

In thousands December 31,	1996	1995
ASSETS		
Utility plant, at original cost	$20,400,387	$19,850,179
Less—accumulated provision for depreciation and decommissioning	9,431,071	8,569,265
	10,969,316	11,280,914
Construction work in progress	556,645	727,865
Nuclear fuel, at amortized cost	176,827	139,411
Total utility plant	11,702,788	12,148,190
Nonutility property—less accumulated provision for depreciation of $25,102 and $25,454 at respective dates	63,931	70,191
Nuclear decommissioning trusts	1,485,525	1,260,095
Other investments	103,973	65,963
Total other property and investments	1,653,429	1,396,249
Cash and equivalents	319,942	261,767
Receivables, including unbilled revenue, less allowances of $26,079 and $24,139 for uncollectible accounts at respective dates	921,083	911,963
Fuel inventory	72,480	114,357
Materials and supplies, at average cost	154,266	151,180
Accumulated deferred income taxes—net	240,429	476,725
Prepayments and other current assets	105,137	114,289
Total current assets	1,813,337	2,030,281
Unamortized debt issuance and reacquisition expense	346,834	350,563
Rate phase-in plan	50,703	129,714
Unamortized nuclear plant—net	-	67,185
Income tax-related deferred charges	1,741,091	1,723,605
Other deferred charges	428,370	309,328
Total deferred charges	2,566,998	2,580,395
Total assets	$17,736,552	$18,155,115

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

In thousands, except share amounts December 31,	1996	1995
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 and other	210,857	195,815
Retained earnings	2,665,612	2,780,058
	5,044,523	5,143,927
Preferred stock:		
Not subject to mandatory redemption	283,755	283,755
Subject to mandatory redemption	275,000	275,000
Long-term debt	4,778,703	5,215,117
Total capitalization	10,381,981	10,917,799
Other long-term liabilities	423,925	344,192
Current portion of long-term debt	501,470	1,375
Short-term debt	230,149	359,508
Accounts payable	392,779	346,258
Accrued taxes	484,688	550,384
Accrued interest	93,363	86,494
Dividends payable	108,563	138,334
Regulatory balancing accounts—net	181,488	337,867
Deferred unbilled revenue and other current liabilities	825,317	778,476
Total current liabilities	2,817,817	2,598,696
Accumulated deferred income taxes—net	3,170,696	3,323,190
Accumulated deferred investment tax credits	347,118	374,142
Customer advances and other deferred credits	595,015	597,096
Total deferred credits	4,112,829	4,294,428
Commitments and contingencies (Notes 2, 8, 9 and 10)		
Total capitalization and liabilities	$17,736,552	$18,155,115

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,	1996	1995	1994
Cash flows from operating activities:			
Net income	$ 655,395	$ 679,691	$ 638,581
Adjustments for non-cash items:			
Depreciation and decommissioning	1,063,505	954,141	890,656
Amortization	90,931	68,064	126,131
Rate phase-in plan	79,011	111,016	123,479
Deferred income taxes and investment tax credits	46,122	(208,671)	(95,218)
Other long-term liabilities	79,733	33,129	44,468
Other—net	(153,034)	(261)	(23,841)
Changes in working capital:			
Receivables	(9,120)	(9,873)	(64,311)
Regulatory balancing accounts	(156,379)	282,157	(2,222)
Fuel inventory, materials and supplies	38,791	(19,499)	(21,087)
Prepayments and other current assets	9,152	(15,511)	(1,260)
Accrued interest and taxes	(58,827)	34,704	117,819
Accounts payable and other current liabilities	93,362	45,355	89,682
Net cash provided by operating activities	1,778,642	1,954,442	1,822,877
Cash flows from financing activities:			
Long-term debt issued	396,309	393,829	964
Long-term debt repayments	(403,957)	(422,503)	(170,224)
Preferred stock redemptions	-	(75,000)	-
Nuclear fuel financing—net	41,803	31,134	(31,444)
Short-term debt financing—net	(129,359)	(316,006)	62,420
Dividends paid	(799,593)	(559,886)	(588,917)
Net cash used by financing activities	(894,797)	(948,432)	(727,201)
Cash flows from investing activities:			
Additions to property and plant	(616,427)	(772,950)	(981,894)
Funding of nuclear decommissioning trusts	(148,158)	(150,595)	(130,155)
Unrealized gain in equity investments	14,900	8,483	9,999
Other—net	(75,985)	(21,273)	(6,453)
Net cash used by investing activities	(825,670)	(936,335)	(1,108,503)
Net increase (decrease) in cash and equivalents	58,175	69,675	(12,827)
Cash and equivalents, beginning of year	261,767	192,092	204,919
Cash and equivalents, end of year	$ 319,942	$ 261,767	$ 192,092
Cash payments for interest and taxes:			
Interest	$ 348,691	$ 382,798	$ 365,126
Taxes	545,834	692,780	443,801

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

Note 1. Summary of Significant Accounting Policies

Southern California Edison Company's (SCE) outstanding common stock is owned entirely by its parent company, Edison International. SCE is a public utility which produces and supplies electric energy for its 4.2 million customers in Central and Southern California. The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated.

SCE's accounting policies conform with generally accepted accounting principles (GAAP), 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).

SCE currently operates in a highly regulated environment in which it has an obligation to provide 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. Financial statements prepared in compliance with GAAP 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 industry restructuring, decommissioning and contingencies, are further discussed in Notes 2, 9 and 10, respectively.

Certain prior-year amounts were reclassified to conform to the December 31, 1996, financial statement presentation.

Debt Issuance and Reacquisition Expense

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.

Financial Instruments

SCE enters into interest rate swap and cap agreements to manage its interest rate exposure. Interest rate differentials and premiums for interest rate caps to be paid or received are recorded as adjustments to interest expense.

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.

Investments

Cash equivalents include tax-exempt investments ($261 million at December 31, 1996, and $235 million at December 31, 1995), and time deposits and other investments ($43 million at December 31, 1996, and $23 million at December 31, 1995) with maturities of three months or less.

Net unrealized gains (losses) in equity investments are recorded as a separate component of shareholder's equity under "Additional paid-in capital and other." Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning.

All investments are classified as available-for-sale.

Nuclear

The CPUC authorized rate phase-in plans to defer the collection of $200 million in revenue for each unit at the Palo Verde Nuclear Generating Station during the first four years of operation and recover the deferred revenue (including interest) evenly over the following six years. The phase-in plans ended in February 1996 and September 1996 for Units 1 and 2, respectively. The plan ends in January 1998 for Unit 3.

Decommissioning costs are accrued and recovered in rates over the term of each nuclear facility's operating license through charges to decommissioning expense (see Note 9).

Under the Energy Policy Act of 1992, 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 customer rates.

In August 1992, the CPUC approved a settlement agreement between SCE and the CPUC's Office (formerly Division) of Ratepayer Advocates (ORA) to discontinue operation of San Onofre Nuclear Generating Station Unit 1 at the end of its then-current fuel cycle because operation of the unit was no longer cost-effective. In November 1992, SCE discontinued operation of Unit 1. As part of the agreement, SCE recovered its remaining investment over a four-year period ending August 1996, earning an 8.98% rate of return on rate base.

In October 1994, the CPUC authorized accelerated recovery of SCE's nuclear plant investments by $75 million per year, with a corresponding deceleration in recovery of its transmission and distribution assets through revised depreciation estimates over their remaining useful lives.

In April 1996, the CPUC authorized, and SCE began accelerating, the recovery of its remaining investment of $2.6 billion in San Onofre Units 2 and 3. The accelerated recovery will continue through December 2001 (the original end date of 2003 was changed by legislation enacted in September 1996), earning a 7.35% fixed rate of return (compared to the current 9.49%). Future operating costs, including nuclear fuel and nuclear-fuel financing costs and incremental capital expenditures at San Onofre Units 2 and 3, are subject to an incentive pricing plan whereby SCE receives about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price will flow through to the shareholders. Beginning in 2004, SCE will be required to share equally with ratepayers the benefits received from operation of the units.

Prior to January 1, 1997, the cost of nuclear fuel for Palo Verde, including disposal, was amortized to fuel expense on the basis of generation. Under CPUC rate-making procedures in effect for Palo Verde prior to January 1, 1997, nuclear-fuel financing costs were capitalized until the fuel was placed into production.

Regulatory Balancing Accounts

The differences between CPUC-authorized and actual base-rate revenue from kilowatt-hour sales and CPUC-authorized and actual energy costs are accumulated in balancing accounts until they are refunded to, or recovered from, utility customers through authorized rate adjustments (with interest). Income tax effects on balancing account changes are deferred.

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 are recorded in a balancing account and, at the end of the rate-case cycle, any authorized but unspent RD&D funds are refunded to customers. RD&D expenses were $21 million in 1996, $28 million in 1995 and $63 million in 1994.

Revenue

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

Stock-based Compensation

SCE measures compensation expense relative to stock-based compensation by the intrinsic-value method.

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 1996, and 3.6% for both 1995 and 1994.

Note 2. Regulatory Matters

Electric Utility Industry Restructuring

On September 23, 1996, the State of California enacted legislation to provide a transition to a competitive market structure. The legislation substantially adopts the CPUC's December 1995 restructuring decision (discussed below) by addressing stranded-cost recovery for utilities, 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 would be recovered through the terms of their contracts while most of the remaining transition costs would be recovered through 2001. The legislation also includes provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, thereby allowing SCE to give a rate reduction of at least 10% to these customers, beginning January 1, 1998. The financing would occur with securities issued by the California Infrastructure and Economic Development Bank, or an entity approved by the Bank. The legislation includes 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 based on cost-of-service regulation during the 1998-2001 transition period. In addition, the legislation mandates the implementation of a non-bypassable competition transition charge (CTC) that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the legislation contains provisions for the recovery (through 2006) of reasonable employee-related transition costs incurred and projected for retraining, severance, early retirement, outplacement and related expenses for utility workers. In light of the legislation, the CPUC is reassessing the need to prepare an environmental impact report.

In December 1995, the CPUC issued its decision on restructuring California's electric utility industry. The transition to a new market structure, which is expected to provide competition and customer choice, would begin January 1, 1998, with all consumers participating by 2003 (changed to 2002 by the recently enacted legislation). Key elements of the CPUC decision include:

- Creation of an independent power exchange (PX) to manage electric supply and demand. California's investor-owned utilities would be required to purchase from and sell to the exchange all of their power during the transition period, while other generators could voluntarily participate.

- Creation of an independent system operator (ISO) to have operational control of the utilities' transmission facilities and, therefore, control the scheduling and dispatch of all electricity on the state's power grid.

- Availability of customer choice through time-of-use rates, direct customer access to generation providers with transmission arrangements through the system operator, and customer-arranged "contracts for differences" to manage price fluctuations from the PX.

- Recovery of costs to transition to a competitive market (utility investments, obligations incurred to serve customers under the existing framework and reasonable employee-related costs) through a non-bypassable charge, applied to all customers, called the CTC.

- CPUC-established incentives to encourage voluntary divestiture (through spin-off or sale to an unaffiliated entity) of at least 50% of utilities' gas-fueled generation to address market power issues.

- Performance-based ratemaking (PBR) for those utility services not subject to competition.

In April 1996, SCE, Pacific Gas & Electric Company and San Diego Gas & Electric Company filed a proposal with the FERC regarding the creation of the PX and the ISO. On November 26, 1996, the FERC conditionally accepted the proposal and directed the three utilities to file more specific information by March 31, 1997. In July 1996, the three utilities jointly filed an application with the CPUC requesting approval to establish a restructuring trust which would obtain loans up to $250 million for the development of the ISO and PX through January 1, 1998. The loans would be backed by utility guarantees; SCE's share would be 45%. Once the ISO and PX are formed, they will repay the trust's loans and recover funds from future ISO and PX customers. In August 1996, the CPUC issued an interim order establishing the restructuring trust and the funding level of $250 million which will be used to build the hardware and software systems for the ISO and PX.

Recovery of costs to transition to a competitive market would be implemented through a non-bypassable CTC. This charge would apply to all customers who were using or began using utility services on or after the December 20, 1995, decision date. In August 1996, in compliance with the CPUC's restructuring decision, SCE filed its application to estimate its 1998 transition costs. In October 1996, SCE amended its transition cost filing to reflect the effects of the legislation enacted in September 1996. Under the rate freeze codified in the legislation, the CTC will be determined residually (i.e., after subtracting other cost components for the PX, transmission and distribution (T&D), nuclear decommissioning and public benefit programs). Nevertheless, the CPUC directed that the amended application provide estimates of SCE's potential transition costs from 1998 through 2030. SCE provided two estimates between approximately $13.1 billion (1998 net present value), assuming the fossil plants have a market value equal to their net book value, and $13.8 billion (1998 net present value), assuming the fossil plants have no market value. These estimates are based on incurred costs, and 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: $7.5 billion from SCE's qualifying facility contracts, which are the direct result of legislative and regulatory mandates; and $5.6 billion to $6.3 billion from costs pertaining to certain generating plants and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed-through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre (as discussed in Note 1) and Palo Verde, nuclear decommissioning and certain other costs.

On November 27, 1996, SCE filed an application with the CPUC to voluntarily divest, by auction, all of its oil- and gas-fueled generation assets. This application builds on SCE's March 1996 plan which outlined how SCE proposed to divest 50% of these assets. Under the new proposal, SCE would continue to operate and maintain the divested power plants for at least two years following their sale, as mandated by the recent restructuring legislation. In addition, SCE would offer workforce transition programs to those employees who may be impacted by divestiture-related job reductions. SCE's proposal is contingent on the overall electric industry restructuring implementation process continuing on a satisfactory path. CPUC approval of the oil- and gas-fueled generation divestiture was requested for late 1997.

In September 1996, the CPUC adopted a non-generation T&D PBR mechanism for SCE which began on January 1, 1997. According to the CPUC decision, beginning in 1998, the transmission portion is to be separated from non-generation PBR and subject to ratemaking under the rules of the FERC. The distribution-only PBR will extend through December 2001. Key elements of the non-generation PBR include: T&D rates indexed for inflation based on the Consumer Price Index less a productivity factor; elimination of the kilowatt-hour sales adjustment; 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. In July 1996, SCE filed a PBR proposal for its hydroelectric plants and a proposed structure for performance-based local reliability contracts for certain fossil-fueled plants. If approved, the hydro PBR would be in effect for three years and the initial terms of the local reliability contracts, which are subject to FERC approval, would be in effect for up to three years, both beginning January 1, 1998. A final CPUC decision on hydro PBR is expected by year-end 1997.

In July 1996, SCE filed a proposal with the CPUC related to the conceptual aspects of separating the costs associated with generation, transmission, distribution, public benefit programs and the CTC. The filing was in response to CPUC and FERC directives which require electric services, such as T&D, to be functionally

separate and available to all customers on a nondiscriminatory basis without cost-shifting among customers. On December 6, 1996, SCE filed a more comprehensive plan for the functional unbundling of SCE's rates for electric service, beginning on January 1, 1998. In response to CPUC and FERC orders, as well as the new restructuring legislation, this filing addressed the implementation-level detail for the functional unbundling of rates in separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The filing also included proposals for establishing new regulatory proceedings to replace current proceedings that will no longer be necessary during the rate freeze period.

Although depreciation-related differences could result from applying a regulatory prescribed depreciation method (straight-line, remaining-life method) rather than a method that would have been applied absent the regulatory process, SCE believes that the depreciable lives of its generation-related assets would not vary significantly from that of an unregulated enterprise, as the CPUC bases depreciable lives on periodic studies that reflect the physical useful lives of the assets. SCE also believes that any depreciation-related differences would be recovered through the CTC.

If events occur during the restructuring process that result in all or a portion of the CTC 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 implementation phases, or the effect, after the transition period, that competition will have on its results of operations or financial position.

Subsequent Event

If the CPUC's restructuring is implemented as outlined, SCE would be allowed to recover its CTC (subject to a lower return on equity) and believes it should be allowed to continue to apply accounting standards that recognize the economic effects of rate regulation for its generation-related assets during the 1998-2001 transition period. However, in response to a request by the staff of the Securities and Exchange Commission (SEC), in December 1996, SCE submitted its views on the continued applicability of regulatory accounting standards for its generation-related assets. In its submittal, SCE and its independent accountants jointly concluded that, based on their current analysis, SCE will continue to meet the criteria for applying these accounting standards through the 1998-2001 transition period. In its February 1997 response, the SEC staff expressed continuing concern with SCE's conclusion and indicated that they wanted to meet further with SCE and the other major California electric utilities to resolve this matter. SCE and its independent accountants continue to believe that SCE meets such criteria and plan to meet with the SEC staff to present additional and clarifying information seeking to convince the SEC staff of the merits of SCE's position. The authority to require SCE to discontinue applying regulatory accounting standards rests with the SEC. If SCE is required to discontinue the application of these accounting standards for its generation-related assets, it would have to write off generation-related regulatory assets, which at December 31, 1996, totaled approximately $600 million on an after-tax basis, primarily for the recovery of income tax benefits previously flowed-through to customers, the Palo Verde phase-in plan and unamortized loss on reacquired debt.

SCE believes that a proper application of regulatory accounting standards will result in it no longer meeting the criteria to apply these accounting standards to all of its non-hydroelectric generation-related assets after the end of the 1998-2001 transition period. If SCE continues the application of these accounting standards during the transition period, but during the transition period events occur that result in SCE no longer meeting the criteria for applying such standards, SCE may be required to write off the remaining balance of its recorded generation-related regulatory assets existing at that time.

If a non-cash write-off is required, SCE believes that it should not affect the stranded-cost recovery plans set forth in the CPUC's December 1995 restructuring decision and legislation enacted by the State of California in September 1996.

FERC Stranded Cost/Open Access Transmission Decision

In April 1996, the FERC issued its decision on stranded cost recovery and open access transmission, effective July 1996. The decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with increased access to transmission facilities for wholesale transactions and also establishes information requirements for the transmission utility. The decision also provides utilities with the recovery of stranded costs, which are prior-service costs incurred under the current

regulatory framework. In addition to providing recovery of stranded costs associated with existing wholesale customers, the FERC directed that it would have primary jurisdiction over the recovery of stranded costs associated with retail-turned-wholesale customers, such as the formation of a new municipal electric system. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states and the FERC would only address recovery of these costs if the state has no authority to do so. In compliance with the April 1996 FERC decision, SCE filed a revised open access tariff with the FERC in July 1996. The tariff became effective on an interim basis, subject to refund, as of its filing date. Several wholesale customers have filed protests with the FERC on the transmission rate levels, and a ruling from the FERC setting the rates to be decided at formal hearings is anticipated in early 1997.

Mohave Generating Station

A 1994 CPUC decision stated that SCE was liable for expenditures related to a 1985 accident at the Mohave Generating Station. In July 1996, the CPUC approved a settlement agreement between SCE and the ORA which resulted in a $39 million (including interest) refund to SCE's customers. The refund, which had been previously reserved, was completed by year-end 1996.

Canadian Gas Contracts

In May 1994, SCE filed its testimony in the non-Qualifying Facilities phase of the 1994 Energy Cost Adjustment Clause proceeding. In May 1995, the ORA filed its report on the reasonableness of SCE's gas supply costs for both the 1993 and 1994 record periods. The report recommends a disallowance of $13.3 million for excessive costs incurred from November 1993 through March 1994 associated with SCE's Canadian gas purchase and supply contracts. The report requests that the CPUC defer finding SCE's Canadian supply and transportation agreements reasonable for the duration of their terms and that the costs under these contracts be reviewed on a yearly basis. In October 1996, the ORA issued its report for the 1995 record period recommending a $37.6 million disallowance for excessive costs incurred from April 1994 through March 1995. Both proposed disallowances have been consolidated into one proceeding. SCE and the ORA have filed several rounds of testimony on this issue. Hearings began in January 1997 and are expected to conclude in February 1997. A decision is expected in late 1997.

Palo Verde Rate-making Mechanism

On December 23, 1996, the CPUC issued a final decision on SCE's proposal for a new rate mechanism for its 15.8% share of the three units at Palo Verde. The decision adopts the Palo Verde All-Party Settlement filed with the CPUC on November 15, 1996. The settlement was based on a Memorandum of Understanding signed by all of the active parties to the Palo Verde proceeding. Under the settlement, SCE has the opportunity to recover its remaining investment (approximately $1.2 billion) in Palo Verde beginning January 1, 1997, and ending December 31, 2001, earning a reduced rate of return on rate base of 7.35% instead of the current 9.49%. Also, SCE will utilize a balancing account to pass through Palo Verde's incremental operating costs (considered reasonable as long as they do not exceed 30% of a baseline forecast and the site's gross annual capacity factor does not go below 55%) to ratepayers. Beginning January 1, 1998, this balancing account will become part of the CTC mechanism. If SCE's actual costs are less than the forecast, the difference will benefit ratepayers as a credit to the CTC mechanism. The 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. After 2001, SCE's ratepayers will receive 50% of the benefits derived from the operation of Palo Verde.

Note 3. Financial Instruments

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.

Long-term debt maturities and sinking-fund requirements for the next five years are: 1997—$501 million; 1998—$447 million; 1999—$155 million; 2000—$325 million; and 2001—$400 million.

Long-term debt consisted of:

In millions December 31,	1996	1995
First and refunding mortgage bonds:		
1997—2000 (5.45% to 7.5%)	$ 1,025	$ 1,025
2001—2005 (5.625% to 6.25%)	450	450
2017—2026 (6.9% to 8.875%)	1,250	1,637
Pollution-control bonds:		
1999—2027 (5.4% to 7.2% and variable)	1,204	1,205
Funds held by trustees	(2)	(2)
Debentures and notes:		
1998—2006 (5.6% to 8.25%)	1,195	795
Subordinated debentures:		
2044 (8.375%)	100	100
Commercial paper for nuclear fuel	112	70
Long-term debt due within one year	(501)	(1)
Unamortized debt discount—net	(54)	(64)
Total	$ 4,779	$ 5,215

Short-Term Debt

SCE has lines of credit it can use at negotiated or bank index rates. At December 31, 1996, available lines totaled $1.1 billion, with $600 million 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, balancing account undercollections and general cash requirements. Commercial paper outstanding at December 31, 1996, and 1995, was $345 million and $433 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 5.5% and 5.8%, at December 31, 1996, and 1995, respectively.

Other 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.

Interest rate swaps and caps are used to reduce the potential impact of interest rate fluctuations on floating rate long-term debt. The interest rate swap agreement requires the parties to pledge collateral according to bond rating and market interest rate changes. At December 31, 1996, SCE had pledged $16 million as collateral due to a decline in market interest rates. SCE is exposed to credit loss in the event of nonperformance by counterparties to these agreements, but does not expect the counterparties to fail to meet their obligations.

For both balance sheet dates presented, SCE had the following derivative financial instruments:

Category	Contract Amount/Terms	Purpose
Interest rate swap	$196 million due 2008	fix interest rate exposure at 5.585%
Interest rate cap	$30 million expires 1997 debt due 2027	fix interest rate exposure at 6% over variable term of the debt

Fair values of financial instruments were:

December 31,	1996		1995	
Instrument In millions	Cost Basis	Fair Value	Cost Basis	Fair Value
Financial assets:				
Decommissioning trusts	$1,217	$1,485	$1,069	$1,260
Equity investments	11	68	9	41
Financial liabilities:				
DOE decommissioning and decontamination fees	54	45	58	49
Interest rate swap and cap	—	16	—	18
Long-term debt	4,779	5,001	5,215	5,487
Preferred stock subject to mandatory redemption	275	286	275	288

Financial assets are carried at their fair value, which is based on quoted market prices. 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, preferred stock and the cap; 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 on financial assets were:

In millions December 31,	1996	1995
Decommissioning trusts:		
Municipal bonds	$ 79	$ 52
Stocks	138	122
U.S. government issues	39	11
Short-term and other	12	6
	268	191
Equity investments	57	32
Total	$325	$223

There were no unrealized holding losses on financial assets for the years presented.

Note 4. Equity

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1996, SCE had the capacity to pay $112 million in additional dividends and continue to maintain its authorized capital structure.

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. There are no preferred stock redemption requirements for the next five years.

Cumulative preferred stock consisted of:

Dollars in millions, except per-share amounts	December 31, 1996 Shares Outstanding	December 31, 1996 Redemption Price	1996	1995
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	2,200,000	25.25	55	55
7.36	4,000,000	25.00	100	100
Total			$284	$284
Subject to mandatory redemption:				
$100 par value preferred stock:				
6.05% Series	750,000	$100.00	$ 75	$ 75
6.45	1,000,000	100.00	100	100
7.23	1,000,000	100.00	100	100
Total			$275	$275

In 1995, 750,000 shares of Series 7.58% preferred stock were redeemed. There were no other preferred stock issuances or redemptions 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,	1996	1995
Deferred tax assets:		
Property-related	$ 247	$ 276
Investment tax credits	206	222
Regulatory balancing accounts	205	166
Decommissioning-related	208	73
Other	429	601
Total	$ 1,295	$ 1,338
Deferred tax liabilities:		
Property-related	$ 3,550	$ 3,670
Other	675	514
Total	$ 4,225	$ 4,184
Accumulated deferred income taxes—net	$ 2,930	$ 2,846
Classification of accumulated deferred income taxes:		
Included in deferred credits	$ 3,170	$ 3,323
Included in current assets	240	477

The current and deferred components of income tax expense were:

In millions — Year ended December 31,	1996	1995	1994
Current:			
Federal	$386	$560	$431
State	129	165	123
	515	725	554
Deferred—federal and state:			
Accrued charges	(14)	1	(25)
Depreciation	(14)	21	46
Investment and energy tax credits—net	(24)	(25)	(22)
Pension reserves	45	(3)	(8)
Rate phase-in plan	(32)	(46)	(51)
Regulatory balancing accounts	34	(118)	(7)
State tax privilege year	21	(12)	(14)
Other	(20)	(33)	(21)
	(4)	(215)	(102)
Total income tax expense	$511	$510	$452
Classification of income taxes:			
Included in operating income	$578	$560	$508
Included in other income	(67)	(50)	(56)

The composite federal and state statutory income tax rate was 41.045% for all years presented.

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

Year ended December 31,	1996	1995	1994
Federal statutory rate	35.0%	35.0%	35.0%
Capitalized software	(0.8)	(0.8)	(2.1)
Depreciation and other	4.5	4.3	4.9
Investment and energy tax credits	(2.0)	(2.2)	(2.0)
State tax—net of federal deduction	7.1	6.5	5.7
Effective tax rate	43.8%	42.8%	41.5%

Note 6. Employee Benefit Plans

Stock Option Plans

Under its Long-Term Incentive Compensation Plan, SCE participates 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, there are currently outstanding to officers and senior managers of SCE, options on 2.9 million shares of Edison International common stock.

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. The optionee has no right to payment of these dividend equivalents until the underlying stock options are exercised. For Edison International stock options issued subsequent to 1993, dividend equivalents are subject to reduction unless certain shareholder return performance criteria are met.

Edison International 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. The options are not transferable, except by will or domestic relations order. If an optionee retires, dies or is permanently and totally disabled during the three-year vesting period, the unvested options will vest and be exercisable to the extent of 1/36 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 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.

Compensation expense recorded under the stock-compensation program was $8 million, $4 million and $(2) million for 1996, 1995 and 1994, respectively. A decline during 1994 in the market value of the underlying shares optioned resulted in the recapture of previously recognized expense.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma net income of approximately $653 million in 1996 and $677 million in 1995.

The weighted-average fair value of options granted during 1996 and 1995, was $6.27 per share option and $6.92 per share option, respectively. The weighted-average remaining life of options outstanding, as of December 31, 1996, and 1995, was 7 years and 8 years, respectively.

The fair value for each option granted during 1996 and 1995, 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:

	1996	1995
Expected life	7 years	8 years
Risk-free interest rate	5.5%	7.9%
Expected volatility	17%	17%

The recognition of dividend equivalents results in no dividends assumed for purposes of fair-value determination. The application of fair-value accounting in arriving at 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. Benefits are based on years of accredited service and average base pay. SCE funds the plan on a level-premium actuarial method. These funds are accumulated in an independent trust. Annual contributions meet minimum legal funding requirements and do not exceed the maximum amounts deductible for income taxes. Prior service costs from pension plan amendments are funded over 30 years. Plan assets are primarily common stocks, corporate and government bonds, and short-term investments. In 1996, SCE recorded pension gains from a special voluntary early retirement program.

The plan's funded status was:

In millions December 31,	1996	1995
Actuarial present value of benefit obligations:		
Vested benefits	$1,670	$1,696
Nonvested benefits	71	210
Accumulated benefit obligation	1,741	1,906
Value of projected future compensation levels	261	479
Projected benefit obligation	$2,002	$2,385
Fair value of plan assets	$2,165	$2,620
Projected benefit obligation less than plan assets	$ (163)	$ (235)
Unrecognized net gain	300	326
Unrecognized prior service cost	(199)	(6)
Unrecognized net obligation (17-year amortization)	(43)	(49)
Pension liability (asset)	$ (105)	$ 36
Discount rate	7.75%	7.25%
Rate of increase in future compensation	5.0%	5.0%
Expected long-term rate of return on assets	8.0%	8.0%

SCE recognizes pension expense calculated under the actuarial method used for ratemaking.

The components of pension expense were:

In millions Year ended December 31,	1996	1995	1994
Service cost for benefits earned	$ 49	$ 57	$ 67
Interest cost on projected benefit obligation	178	156	148
Actual return on plan assets	(343)	(454)	(28)
Net amortization and deferral	145	268	(140)
Pension expense under accounting standards	29	27	47
Special termination benefits	—	3	15
Regulatory adjustment—deferred	22	22	1
Net pension expense recognized	51	52	63
Settlement gain	(121)	—	—
Total expense (gain)	$ (70)	$ 52	$ 63

Postretirement Benefits Other Than Pensions

Employees retiring at or after age 55 with at least 10 years of service (or those eligible under the 1996 special voluntary early retirement program), are eligible for postretirement health and dental care, life insurance and other benefits. Health and dental care benefits are subject to deductibles, copayment provisions and other limitations.

SCE is amortizing its obligation related to prior service over 20 years. SCE funds these benefits (by contributions to independent trusts) up to tax-deductible limits, in accordance with rate-making practices. In 1996, SCE recorded special termination expenses due to a special voluntary early retirement program. Any difference between recognized expense and amounts authorized for rate recovery is not expected to be material (except for the impact of the early retirement program) and will be charged to earnings.

Trust assets are primarily common stocks, corporate and government bonds, and short-term investments.

The funded status of these benefits is reconciled to the recorded liability below:

In millions December 31,	1996	1995
Actuarial present value of benefit obligation:		
Retirees	$ 928	$ 402
Employees eligible to retire	35	103
Other employees	386	556
Accumulated benefit obligation	$1,349	$1,061
Fair value of plan assets	$ 617	$ 400
Plan assets less than accumulated benefit obligation	$ 732	$ 661
Unrecognized transition obligation	(430)	(457)
Unrecognized net gain (loss)	(231)	(203)
Recorded liability	$ 71	$ 1
Discount rate	7.75%	7.5%
Expected long-term rate of return on assets	8.5%	8.5%

The components of postretirement benefits other than pensions expense were:

In millions Year ended December 31,	1996	1995	1994
Service cost for benefits earned	$ 31	$ 35	$ 29
Interest cost on benefit obligation	90	77	72
Actual return on plan assets	(43)	(28)	(20)
Amortization of loss	6	1	—
Amortization of transition obligation	27	27	36
Net expense	111	112	117
Amortization of prior funding	—	—	2
Special termination expense	72	—	—
Total expense	$ 183	$ 112	$ 119

The assumed rate of future increases in the per-capita cost of health care benefits is 8.25% for 1997, gradually decreasing to 5% for 2004 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 1996, by $206 million 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 $24 million in 1996, $19 million in 1995 and $21 million in 1994.

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, 1996, was:

In millions	Plant in Service	Accumulated Depreciation	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	$ 29	$ 8	$ 2	60%
Pacific Intertie	227	72	12	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	458	236	2	48
Mohave (coal)	300	142	8	56
Palo Verde (nuclear)	1,596	425	6	16
San Onofre (nuclear)	4,186	1,836	28	75
Total	$6,796	$2,719	$ 58	

Note 8. Leases

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

Estimated remaining commitments for noncancelable leases at December 31, 1996, were:

Year ended December 31,	In millions
1997	$18
1998	15
1999	11
2000	9
2001	5
Thereafter	7
Total	$65

Note 9. Commitments

Nuclear Decommissioning

SCE plans to decommission its nuclear generating facilities at the end of each facility's operating license by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is estimated to cost $2.0 billion in current-year dollars, based on site-specific studies performed in 1993 for San Onofre and 1992 for 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. Decommissioning is scheduled to begin in 2013 at San Onofre and 2024 at Palo Verde. San Onofre Unit 1, which shut down in 1992, is expected to be secured until decommissioning begins at the other San Onofre units.

Decommissioning costs, which are recovered through customer rates, are recorded as a component of depreciation expense. Decommissioning expense was $148 million in 1996, $151 million in 1995 and $122 million in 1994. The accumulated provision for decommissioning was $949 million at December 31, 1996,

and $823 million at December 31, 1995. The estimated costs to decommission San Onofre Unit 1 ($263 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, 1996	December 31, 1995
Municipal bonds	1999-2021	$ 400	$ 348
Stocks	-	549	390
U.S. government issues	1998-2024	212	145
Short-term and other	1996-2024	56	186
Trust fund balance (at cost)		$1,217	$1,069

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $49 million in 1996, $51 million in 1995 and $26 million in 1994. Proceeds from the sales of securities (which are reinvested) were $1.0 billion in both 1996 and 1995, and $1.1 billion in 1994. Approximately 89% of the trust fund contributions were tax-deductible.

The Financial Accounting Standards Board has issued an exposure draft related to accounting practices for removal costs, including decommissioning of nuclear power plants. The exposure draft would require SCE to report its estimated decommissioning costs as a liability, rather than recognizing these costs over the term of each facility's operating license (current industry practice). SCE does not believe that the changes proposed in the exposure draft would have an adverse effect on its results of operations even after deregulation due to its current and expected future ability to recover these costs through customer rates.

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. The qualifying facility 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 $205 million through 2017.

Certain commitments for the years 1997 through 2001 are estimated below:

In millions	1997	1998	1999	2000	2001
Projected construction expenditures	$ 802	$ 636	$ 664	$ 647	$ 650
Fuel supply contracts	269	231	221	240	234
Purchased-power capacity payments	696	699	701	702	695
Unconditional purchase obligations	9	10	10	10	10

Note 10. Contingencies

In addition to the matters disclosed in these notes, SCE is involved in 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 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). While SCE has numerous insurance policies that it believes may provide coverage for some of these liabilities, it does not recognize recoveries in its financial statements until they are realized.

SCE's recorded estimated minimum liability to remediate its 55 identified sites was $114 million at December 31, 1996. 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 $211 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental-cleanup costs at 35 of its sites, representing $101 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 a number of its carriers. Costs incurred at the remaining 20 sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $104 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 $8 million. Recorded costs for 1996 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 have a material adverse effect on 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 $8.9 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 $79 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 $158 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 has also 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 $34 million per year. Insurance premiums are charged to operating expense.

Quarterly Financial Data

	1996					1995				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue	$7,583	$1,866	$2,346	$1,611	$1,760	$7,873	$1,903	$2,510	$1,738	$1,722
Operating income	1,133	231	382	257	263	1,149	246	369	261	273
Net income	655	121	256	131	147	680	130	251	150	149
Earnings available for common stock	621	113	247	123	138	643	121	243	140	139
Common dividends declared	735	196	178	180	181	546	136	136	137	137

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

January 31, 1997

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, 1996, and 1995, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1996. 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 of SCE and its subsidiaries as of December 31, 1996, and 1995, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Los Angeles, California
January 31, 1997 (except with respect to the "Subsequent Event" discussed under "Electric Utility Industry Restructuring" in Note 2, as to which the date is February 21, 1997).

Board of Directors

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Chairman of the Board and CEO, Edison International and SCE

Howard P. Allen
Chairman of the Executive Committee, Edison International and SCE

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

Stephen E. Frank
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Retired Chairman of the Board and CEO, First Interstate Bancorp, Los Angeles, California

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

E. L. Shannon, Jr.
Retired Chairman of the Board, Santa Fe International Corporation, Alhambra, California

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

Thomas C. Sutton
Chairman of the Board and CEO, Pacific Mutual Life Insurance Company, Los Angeles, California

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

James D. Watkins
Admiral USN, Retired, President, Joint Oceanographic Institutions, Inc. and President, Consortium for Oceanographic Research and Education, Washington, D.C.

Edward Zapanta, M.D.
Physician and Neurosurgeon, South Pasadena, California

Executive Officers

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

Vikram S. Budhraja
Senior Vice President, Power Grid Business Unit

Robert G. Foster
Senior Vice President, Public Affairs

Emiko Banfield
Vice President, Shared Services

Pamela A. Bass
Vice President, Customer Solutions Business Unit

Richard K. Bushey
Vice President and Controller

Theodore F. Craver, Jr.
Vice President and Treasurer

John R. Fielder
Vice President, Regulatory Policy and Affairs

Bruce C. Foster
Vice President, San Francisco Regulatory Affairs

Lillian R. Gorman
Vice President, Human Resources

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

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

Frank J. Quevedo
Vice President, Equal Opportunity

Richard M. Rosenblum
Vice President, Distribution Business Unit

Beverly P. Ryder
Corporate Secretary and Special Assistant to the Chairman/CEO

Shareholder Information

Annual Meeting of Shareholders

Thursday, April 17, 1997
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 Stocks

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 and dividend checks; and
- requests to eliminate multiple annual report mailings.

The address of Shareholder Services is:

P.O. Box 400, Rosemead, California 91770-0400
FAX: (818) 302-4815

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