SOUTHERN CALIFORNIA
EDISON

An EDISON INTERNATIONAL℠ Company

A. Edward Scherer
Manager of
Nuclear Regulatory Affairs

May 5, 2000

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D. C. 20555

Subject: **Docket Nos. 50-361, 50-362, 50-528, 50-529, and 50-530
Internal Cash Flow for San Onofre Nuclear Generating Station
Units 2 and 3, and Palo Verde Nuclear Generating Station
Units 1, 2, and 3**

Gentlemen:

Southern California Edison (SCE), as agent for the owners of San Onofre Nuclear Generating Stations Units 2 and 3 and with SCE's 15.8% ownership share of Palo Verde Units 1, 2, and 3, submits the following documents in accordance with the provisions of 10 CFR 140.21 (e):

- 2000 Internal Cash Flow Projection which is derived from Consolidated Financial Statements included in SCE's 1999 Annual Report to Shareholders, as audited and certified by Arthur Anderson, LLP.

- SCE's Annual Report to Shareholders for the fiscal year ending December 31, 1999.

- SCE's Form 10-K Annual Report to the Securities and Exchange Commission (Form 10-K) for the fiscal year ending December 31, 1999.

If you have any questions or require further information about these documents, please contact me or Mr. Jack Rainsberry (949/368-7420).

Sincerely,

Enclosures

cc: E. W. Merschoff, Regional Administrator, NRC Region IV
L. Raghavan, NRC Project Manager, San Onofre Units 2 and 3
J. A. Sloan, NRC Senior Resident Inspector, San Onofre Units 2 and 3

P. O. Box 128
San Clemente, CA 92674-0128
949-368-7501
Fax 949-368-7575

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SOUTHERN CALIFORNIA EDISON COMPANY

2000 Internal Cash Flow Projection

(Dollars in Thousands)

	1999 Actual	2000 Projected
Net Income After Taxes	$509,421	[1]
Dividends Paid	$685,731	[1]
Retained Earnings	($176,310)	[1]
Adjustments:		
Depreciation & Decommissioning	$1,546,312	$1,522,768
Net Deferred Taxes & ITC	$177,599	($199,860)
Allowance for Funds Used During Construction	($24,296)	($22,913)
Total Adjustments	$1,699,615	$1,299,995
Internal Cash Flow	$1,523,305	[1]
Average Quarterly Cash Flow	$380,826	[1]
Percentage Ownership in All Nuclear Units:		
San Onofre Nuclear Generating Station Units 2 & 3		
o Southern California Edison Company	75.05%	
o San Diego Gas & Electric Company	20.00%	
o City of Anaheim	3.16%	
o City of Riverside	1.79%	
Palo Verde Nuclear Generating Station Units 1, 2 & 3	15.80%	
Maximum Total Contingent Liability:		
San Onofre Nuclear Generating Station Unit 2	$10,000	
San Onofre Nuclear Generating Station Unit 3	$10,000	
Palo Verde Nuclear Generating Station Unit 1	$1,580	
Palo Verde Nuclear Generating Station Unit 2	$1,580	
Palo Verde Nuclear Generating Station Unit 3	$1,580	
Total	$24,740	

[1] Company policy prohibits disclosure of financial data which will enable unauthorized persons to forecast earnings or dividends, unless assured confidentiality.

SOUTHERN CALIFORNIA

EDISON

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1999 Annual Report

A Profile of Southern California Edison Company

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

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

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

Results of Operations

Earnings

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

Operating Revenue

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

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

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

The changes in operating revenue resulted from:

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

Operating Expenses

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

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

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

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

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

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

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

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

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

Other Income

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

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

Interest Expense

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

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

Financial Condition

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

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

Cash Flows from Operating Activities

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

Cash Flows from Financing Activities

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

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

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

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from non-bypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these non-bypassable residential and small commercial customer rates which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities beginning in 2000 and ending in 2007, with interest rates ranging from 6.14% to 6.42%. The notes are secured by the transition property and are not secured by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities.

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

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

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant, proceeds from the sale of plant and funding of nuclear decommissioning trusts. Decommissioning costs are accrued and recovered in rates over the term of each nuclear generating facility's operating license. SCE estimates that it will spend approximately $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning costs ($2.0 billion), escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts which receive SCE contributions of approximately $25 million per year.

Market Risk Exposures

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

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

As a result of the rate freeze established in the restructuring legislation, SCE's transition costs are recovered as the residual component of rates once the costs for distribution, transmission, public purpose programs, nuclear decommissioning and the cost of supplying power to its customers through the PX and ISO have already been recovered. Accordingly, more revenue will be available to cover transition costs when market prices in the PX and ISO are low than when PX and ISO prices are high. The PX and ISO market prices to date have generally been consistent, although some irregular price spikes have occurred. The ISO has responded to price spikes in the market for reliability services (referred to as ancillary services) by imposing a price cap on the market for such services until certain actions have been completed to improve the functioning of those markets. Similarly, the ISO currently maintains a cap on its market for imbalance energy until adequate measures to improve the efficient operation of the market have been implemented. The caps in these markets mitigate the risk of costly price spikes that would reduce the revenue available to SCE to pay transition costs. The price cap instituted by the ISO in the summer of 1998 was $250/MWh. In October 1999, that cap was raised to $750/MWh and will remain at that level through the summer of 2000, unless certain identified market improvements do not occur. Under such circumstances, the price cap can be reduced to $500/MWh. SCE has entered into gas call options to mitigate high natural gas prices, since increases in natural gas prices tend to raise the price of electricity.

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

Projected Capital Requirements

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

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

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

Regulatory Environment

SCE currently operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing as a result of a 1995 CPUC decision on restructuring and state legislation enacted in 1996. The Statute substantially adopted the CPUC's restructuring decision by addressing stranded-cost recovery for utilities and providing a certain cost-recovery time period for the transition costs associated with generation-related assets. The Statute also included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. The Statute mandated other rates to remain frozen at June 1996 levels (system average of 10.1¢ per kilowatt-hour), including those for large commercial and industrial customers, and included provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement during the 1998—2001 transition period. In addition, the Statute mandated the implementation of the CTC (see the detailed discussion in Revenue and Cost-Recovery Mechanisms) that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring.

Revenue and Cost-Recovery Mechanisms

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

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

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

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

In March 1997, SCE filed its first FERC transmission rate case. In March 1999, a proposed FERC decision was issued which recommended a reduced rate of return on equity of 9.68% (compared to SCE's current CPUC rate for distribution of 11.6%) and a reduced return on transmission assets of 8.41% (compared to the current rate of 9.43% being earned on transmission assets). SCE filed comments opposing the proposed decision in May 1999. In response to a recent FERC ruling, on November 1, 1999, SCE filed additional evidence regarding return on equity. A final FERC decision is expected during first quarter 2000. SCE does not expect the final decision to have a material effect on its results of operations or financial position.

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

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

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

Restructuring Implementation Costs

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

Accounting for Generation-Related Assets

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

During the second quarter of 1998, additional guidance was developed related to the application of asset impairment standards to these assets. Using this guidance, SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recording a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

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

Environmental Protection

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

As further discussed in Note 11 to the Consolidated Financial Statements, SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE's recorded estimated minimum liability to remediate its 45 identified sites is $163 million. One of SCE's sites, a former pole-treating facility, is considered a federal Superfund site and represents 40% of its recorded liability. SCE believes that, due to the uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $284 million. In 1998, SCE sold all of its gas- and oil-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 42 of its sites, representing $90 million of its recorded liability, through an incentive mechanism, which is discussed in Note 11. SCE has recorded a regulatory asset of $126 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information. As a result, no reasonable estimate of cleanup costs can be made for these sites. SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $5 million to $15 million. Recorded costs for 1999 were $14 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

The 1990 Federal Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). A study was undertaken to determine the specific impact of air contaminant emissions from the Mohave Generating Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. In June 1999, the Environmental Protection Agency issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. SCE filed comments on the proposed rulemaking in November 1999. In 1998, several environmental groups filed suit against the co-owners of the Mohave station regarding alleged violations of emissions limits. In order to accelerate resolution of key environmental issues regarding the plant, the parties filed, in concurrence with SCE and the other station owners, a consent decree, which was approved by the court in December 1999. The Environmental Protection Agency has notified SCE that the visibility concerns can be resolved by revising the Mohave station's Federal Implementation Plan to include the relevant provisions in the consent decree.

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

San Onofre Steam Generator Tubes

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

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

New Accounting Rules

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

Year 2000 Issue

SCE implemented a comprehensive program to address potential Year 2000 computer system impacts, consisting of five phases: inventory, impact assessment, remediation, testing and implementation. SCE met its goal to have 100% of its critical systems Year 2000-ready by July 1, 1999. A critical system was defined as those applications and systems, including embedded processor technology, which if not appropriately remediated, may have had a significant impact on customers, the health and safety of the public and/or personnel, the revenue stream, or regulatory compliance. A system, application or physical asset was deemed to be Year 2000-ready if it was determined by SCE to be suitable for continued use through 2028 (or through the last year of the anticipated life of the asset, whichever occurred first), even if not fully Year 2000-compliant (able to accurately process date/time data, between the 20th and 21st centuries, 1999 and 2000, and leap-year calculations).

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

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

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

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

Forward-looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of such important factors as further actions by state and federal regulatory bodies setting rates and implementing the restructuring of the electric utility industry; the effects of new laws and regulations relating to restructuring and other matters; the effects of increased competition in the electric utility business and other energy-related businesses, including direct customer access to retail energy suppliers and the unbundling of revenue cycle services such as metering and billing; changes in prices of electricity and fuel costs; changes in market interest rates; new or increased environmental liabilities; the ability to create and expand new businesses such as telecommunications; and other unforeseen events.

Consolidated Statements of Income

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

Consolidated Statements of Comprehensive Income

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

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

Consolidated Balance Sheets

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

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

Southern California Edison Company

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

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

Consolidated Statements of Cash Flows

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

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

Consolidated Statement of Changes in Common Shareholder's Equity

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

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

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

Note 1. Summary of Significant Accounting Policies

Nature of Operations

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

Basis of Presentation

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

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated. Certain prior-year amounts were reclassified to conform to the December 31, 1999, financial statement presentation.

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

Estimates

Financial statements prepared in compliance with generally accepted accounting principles require management to make estimates and assumptions that affect the amounts reported in the financial statements and disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to regulatory matters, decommissioning and contingencies are further discussed in Notes 2, 10 and 11 to the Consolidated Financial Statements, respectively.

Cash Equivalents

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

Fuel Inventory

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

Revenue

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

Investments

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

All investments are classified as available-for-sale.

Regulation of Utility Business

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

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

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

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

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

Transactions through the PX were:

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

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future revenue associated with certain costs that will be recovered from customers through the rate-making process, and regulatory liabilities, which represent probable future reductions in revenue associated with amounts that are to be credited to customers through the rate-making process. SCE's discontinuance of accounting principles for rate-regulated enterprises to its generation assets did not result in a write-off of its generation-related regulatory assets since the CPUC has approved recovery of these assets through the CTC.

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

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

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

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

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

Regulatory Balancing Accounts

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

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

Income tax effects on all balancing account changes are deferred.

Nuclear

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

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

Utility Plant

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

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.6% for 1999, 4.2% for 1998 and 5.2% for 1997.

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

Supplemental Cash Flows Information

SCE's supplemental cash flows information was:

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

Note 2. Regulatory Matters

FERC Transmission Rate Case

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

Hydroelectric Market Value Filing

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

Note 3. Financial Instruments

Derivative Financial Instruments

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

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

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

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

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

Fair Value of Financial Instruments

Fair values of financial instruments were:

In millions December 31,	1999		1998	
	Cost Basis	**Fair Value**	Cost Basis	Fair Value
Financial assets:				
Decommissioning trusts	**$1,650**	**$2,509**	$1,534	$2,240
Equity investments	**—**	**33**	7	72
Gas call options	**28**	**20**	39	31
PX block forward power contracts	**118**	**120**	—	—
Financial liabilities:				
DOE decommissioning and decontamination fees	**40**	**35**	45	40
Interest rate hedges	**—**	**13**	—	28
Long-term debt	**5,137**	**5,044**	5,447	5,699
Preferred stock subject to mandatory redemption	**256**	**259**	256	274

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

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

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

There were no unrealized holding losses for the years presented.

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

Note 4. Long-Term Debt

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

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE uses these proceeds to finance construction of pollution-control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

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

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

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

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from non-bypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these non-bypassable residential and small commercial customer rates which constitute the transition property purchased by SCE Funding LLC. The notes are secured by the transition property and are not secured by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities.

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

Long-term debt consisted of:

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

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

Note 5. Short-Term Debt

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

Short-term debt includes commercial paper used to finance fuel inventories and general cash requirements. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks. Weighted-average interest rates were 6.1% and 5.3% at December 31, 1999, and December 31, 1998, respectively.

Short-term debt consisted of:

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

Note 6. Preferred Stock

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

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

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

Cumulative preferred stock consisted of:

Dollars in millions, except per share amounts	December 31, 1999 Shares Outstanding	December 31, 1999 Redemption Price	1999	1998
Not subject to mandatory redemption:				
$25 par value:				
4.08% Series	1,000,000	$25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Total			**$129**	$129
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$100.00	**$ 75**	$ 75
6.45	1,000,000	100.00	**100**	100
7.23	807,000	100.00	**81**	81
Total			**$256**	$256

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

Note 7. Income Taxes

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

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

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

In millions December 31,	1999	1998
Deferred tax assets:		
Property-related	**$ 184**	$ 197
Unrealized gains or losses	**453**	387
Investment tax credits	**113**	152
Regulatory balancing accounts	**67**	96
Decommissioning-related	**127**	126
Fixed costs	**247**	188
Unbilled revenue	**122**	117
Other	**92**	168
Total	**$1,405**	$1,431
Deferred tax liabilities:		
Property-related	**$2,629**	$3,005
Capitalized software costs	**225**	196
Regulatory balancing accounts	**448**	162
Unrealized gains and losses - decommissioning	**351**	284
Other	**502**	502
Total	**$4,155**	$4,149
Accumulated deferred income taxes — net	**$2,750**	$2,718
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$2,938**	$2,993
Included in current assets	**188**	275

The current and deferred components of income tax expense were:

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

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

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

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

Note 8. Employee Compensation and Benefit Plans

Employee Savings Plan

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

Pension Plan

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

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

Information on plan assets and benefit obligations is shown below:

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

Expense components were:

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

Postretirement Benefits Other Than Pensions

Employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits. In 1998, SCE adopted a new accounting standard that revises the disclosure requirements for postretirement benefit plans. Prior periods have been restated.

Information on plan assets and benefit obligations is shown below:

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

Expense components were:

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

The assumed rate of future increases in the per-capita cost of health care benefits is 11.75% for 2000, gradually decreasing to 5.0% for 2008 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 1999, by $227 million and annual aggregate service and interest costs by $28 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 1999, by $183 million and annual aggregate service and interest costs by $22 million.

Stock Option Plans

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

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

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

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

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

Unvested options of any person who has served in the past on the Edison International or SCE Management Committee (which was dissolved in 1993) will vest and be exercisable upon the member's retirement, death or permanent and total disability. Upon retirement, death or permanent and total disability, the vested options may continue to be exercised within their original terms by the recipient or beneficiary. If an optionee is terminated other than by retirement, death or permanent and total disability, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

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

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

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

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

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

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

Note 9. Jointly Owned Utility Projects

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

The investment in each project, as included in the consolidated balance sheet as of December 31, 1999, was:

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

[1] Reported as Unamortized nuclear investment — net."

Note 10. Commitments

Leases

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

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

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

Nuclear Decommissioning

Decommissioning is estimated to cost $2.0 billion in current-year dollars, based on site-specific studies performed in 1998 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current dollar decommissioning costs, escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which, effective 1999, receive contributions of approximately $25 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.9% to 4.9%.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses expire in 2013 for San Onofre Units 2 and 3, and 2025—2027 for Palo Verde. Decommissioning costs, which are accrued and recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

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

Decommissioning expense was $124 million in 1999, $164 million in 1998 and $154 million in 1997. The accumulated provision for decommissioning, excluding San Onofre Unit 1, was $1.3 billion at December 31, 1999, and $1.2 billion at December 31, 1998. The estimated costs to decommission San Onofre Unit 1 (approximately $360 million) are recorded as a liability.

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

Trust investments (cost basis) include:

In millions	Maturity Dates	December 31,	**1999**	1998
Municipal bonds	2000—2033		**$ 684**	$ 547
Stocks	—		**482**	550
U.S. government issues	2000—2030		**351**	355
Short-term and other	2000—2040		**133**	82
Trust fund balance			**$1,650**	$1,534

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $58 million in 1999, $63 million in 1998 and $54 million in 1997. Proceeds from sales of securities (which are reinvested) were $2.6 billion in 1999, $1.2 billion in 1998 and $595 million in 1997. Approximately 90% of the trust fund contributions were tax-deductible.

Other Commitments

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

SCE has power-purchase contracts with certain qualifying facilities (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. As a result of the utility industry restructuring, SCE has entered into purchased-power settlements to end its contract obligations with certain qualifying facilities. The settlements are reported as long-term liabilities. Settlement payments are being recovered through the CTC.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $166 million through 2017. The purchased-power contract (approximately $30 million) is expected to provide approximately 5.5% of current or estimated future operating capacity, and is reported as a long-term liability. The transmission service contract requires a minimum payment of approximately $6 million a year.

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

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

Note 11. Contingencies

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

Environmental Protection

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

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

SCE's recorded estimated minimum liability to remediate its 45 identified sites is $163 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $284 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In 1998, SCE sold all of its gas- and oil-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 42 of its sites, representing $90 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $126 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $5 million to $15 million. Recorded costs for 1999 were $14 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the U.S. results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $88 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $175 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued by a mutual insurance company owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $19 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and development of a facility for disposal of spent nuclear fuel and high-level radioactive waste. Such a facility was to be in operation by January 1998. However, the DOE did not meet its obligation. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or from other nuclear power plants.

SCE has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. Meeting spent-fuel storage requirements beyond that period would require new and separate interim storage facilities, the costs for which have not been determined. Extended delays by the DOE could lead to consideration of costly alternatives involving siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983, (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

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

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

Quarterly Financial Data

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

Responsibility for Financial Reporting

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

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

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

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

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

Thomas M. Noonan
Vice President
and Controller

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

February 2, 2000

Report of Independent Public Accountants

To the Shareholders and the Board of Directors,
Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, a California corporation) and its subsidiaries as of December 31, 1999, and 1998, and the related consolidated statements of income, comprehensive income, cash flows and common shareholder's equity for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of SCE's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of SCE and its subsidiaries as of December 31, 1999, and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP
ARTHUR ANDERSEN LLP

Los Angeles, California
February 2, 2000

Selected Financial and Operating Data: 1995-1999

Southern California Edison Company

Dollars in millions	**1999**	1998	1997	1996	1995
Income statement data:					
Operating revenue	**$ 7,522**	$ 7,500	$ 7,953	$ 7,583	$ 7,873
Operating expenses[1]	**6,674**	6,582	6,893	6,450	6,724
Fuel and purchased power expenses	**3,404**	3,586	3,735	3,336	3,197
Income tax from operations	**449**	446	582	578	560
Allowance for funds used during construction	**24**	20	17	25	34
Interest expense — net	**483**	485	444	453	464
Net income	**509**	515	606	655	680
Earnings available for common stock	**484**	490	576	621	643
Ratio of earnings to fixed charges	**2.94**	2.95	3.49	3.54	3.52
Balance sheet data:					
Assets	**$17,657**	$16,947	$18,059	$17,737	$18,155
Gross utility plant	**14,852**	14,150	21,483	21,134	20,717
Accumulated provision for depreciation and decommissioning	**7,520**	6,896	10,544	9,431	8,569
Common shareholder's equity	**3,133**	3,335	3,958	5,045	5,144
Preferred stock:					
Not subject to mandatory redemption	**129**	129	184	284	284
Subject to mandatory redemption	**256**	256	275	275	275
Long-term debt	**5,137**	5,447	6,145	4,779	5,215
Capital structure:					
Common shareholder's equity	**36.2%**	36.4%	37.5%	48.6%	47.1%
Preferred stock:					
Not subject to mandatory redemption	**1.5%**	1.4%	1.7%	2.7%	2.6%
Subject to mandatory redemption	**2.9%**	2.8%	2.6%	2.7%	2.5%
Long-term debt	**59.4%**	59.4%	58.2%	46.0%	47.8%
Operating data:					
Peak demand in megawatts (MW)	**19,122**	19,935	19,118	18,207	17,548
Generation capacity at peak (MW)	**10,474**	10,546	21,511	21,602	21,603
Kilowatt-hour sales (kWh) (in millions)	**78,602**	76,595	77,234	75,572	74,296
Total energy requirement (kWh) (in millions)[2]	**78,752**	80,289	86,849	84,236	81,924
Energy mix:					
Thermal	**35.5%**	38.8%	44.6%	47.6%	51.6%
Hydro	**5.6%**	7.4%	6.5%	6.9%	7.7%
Purchased power and other sources	**58.9%**	53.8%	48.9%	45.5%	40.7%
Customers (in millions)	**4.36**	4.27	4.25	4.22	4.18
Full-time employees	**13,040**	13,177	12,642	12,057	14,886

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

Board of Directors

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

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

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

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

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

*Retiring on April 20, 2000.

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

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

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

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

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

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

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

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

Management Team

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

Harold B. Ray
Executive Vice President,
Generation Business Unit

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

John R. Fielder
Senior Vice President,
Regulatory Policy and Affairs

Robert G. Foster
Senior Vice President,
Public Affairs

Lillian R. Gorman*
Senior Vice President,
Human Resources

Richard M. Rosenblum
Senior Vice President,
Transmission and Distribution Business Unit

Mahvash Yazdi
Senior Vice President and Chief Information Officer

*Resigned on February 29, 2000.

Emiko Banfield
Vice President,
Shared Services

Bruce C. Foster
Vice President,
San Francisco Regulatory Operations

A. L. Grant
Vice President, Transmission

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

Holly Kolinski
Vice President,
Mass Customers

R. W. Krieger
Vice President,
Nuclear Generation

J. Michael Mendez
Vice President, Labor Relations

Thomas M. Noonan
Vice President and Controller

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

Stephen E. Pickett
Vice President and General Counsel

Frank J. Quevedo
Vice President,
Equal Opportunity

Joseph P. Ruiz
Vice President and General Auditor

W. James Scilacci
Vice President and Chief Financial Officer

Dale E. Shull, Jr.
Vice President, Distribution

Anthony L. Smith
Vice President, Tax

David Ned Smith
Vice President, Major Customers

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

Robert C. Boada
Treasurer

Beverly P. Ryder
Secretary

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Shareholder Information

Annual Meeting of Shareholders

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

Stock Listing and Trading Information

SCE Preferred Stock

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

Where to Buy and Sell Stock

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

Transfer Agent and Registrar

Norwest Bank Minnesota, N.A. maintains shareholder records and is transfer agent and registrar for SCE preferred stock. Shareholders may call Norwest Shareowner Services, (800) 347-8625, between 7:00 a.m. and 7:00 p.m. (Central Time) every business day, regarding:

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

The address of Norwest Shareowner Services is:

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

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL℠ Company

Southern California Edison
2244 Walnut Grove Avenue
Rosemead, California 91770
(626) 302-1212

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

/X/ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 1999

Commission File Number 1-2313

SOUTHERN CALIFORNIA EDISON COMPANY
(Exact name of registrant as specified in its charter)

California (State or other jurisdiction of incorporation or organization)		95-1240335 (I.R.S. Employer Identification No.)
2244 Walnut Grove Avenue Rosemead, California (Address of principal executive offices)	91770 (Zip Code)	(626) 302-1212 (Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Capital Stock Cumulative Preferred 4.08% Series 4.32% Series 4.24% Series 4.78% Series	American and Pacific

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

As of March 27, 2000, there were 434,888,104 shares of Common Stock outstanding, all of which are held by the registrant's parent holding company. The aggregate market value of registrant's voting stock held by non-affiliates was approximately $330,110,425.50 on or about March 27, 2000, based upon prices reported by the American Stock Exchange. The market values of the various classes of voting stock held by non-affiliates, as of March 27, 2000, were as follows: CUMULATIVE PREFERRED STOCK $74,410,425.50; $100 CUMULATIVE PREFERRED STOCK $255,700,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents listed below have been incorporated by reference into the parts of this report so indicated.

(1)	Designated portions of the Annual Report to Shareholders for the year ended December 31, 1999	Parts I, II and IV
(2)	Designated portions of the Joint Proxy Statement relating to registrant's 2000 Annual Meeting of Shareholders	Part III

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PART I

Item 1. Business

Southern California Edison Company (SCE) was incorporated in 1909 under the laws of the State of California. SCE is a public utility primarily engaged in the business of supplying electric energy to a 50,000 square-mile area of Central and Southern California, excluding the City of Los Angeles and certain other cities. The SCE service territory includes approximately 800 cities and communities and a population of more than 11 million people. Beginning in April 1998, pursuant to the restructuring of the California electric utility industry mandated by a 1996 state law, other entities have had the ability to sell electricity in SCE's service territory, utilizing SCE's transmission and distribution lines at tariffed rates. As a part of this utility industry restructuring, SCE sold some of its electric generating plants in 1998. SCE currently retains other electric generating plants, however, and it retains its transmission and distribution lines over which it transmits and distributes the electricity generated by SCE and other generators to the customers in SCE's service territory. As a further part of the industry restructuring, SCE is required for an interim transitional period (ending no later than year-end 2001) to sell all SCE-generated electricity to the California Power Exchange (PX) at prices determined by periodic public auctions, and SCE is required to buy any electricity needed to serve SCE's retail customers from the PX at similarly determined prices. In 1999, SCE's total operating revenue was derived from: 37.1% residential customers, 38.5% commercial customers, 9.8% industrial customers, 7.1% public authorities, 1.5% agricultural and other customers, and 6.0% other electric revenue. SCE had 13,040 full-time employees at year-end 1999. SCE comprises the largest portion of the assets and revenue of its parent holding company, Edison International.

Forward-Looking Statements

This annual report contains forward-looking statements that reflect SCE's current expectations and projections about future events based on SCE's knowledge of present facts and circumstances and assumptions about future events. Other information distributed by SCE that is incorporated herein or refers to or incorporates this annual report may also contain forward-looking statements. In this annual report and elsewhere, the words "expects," "believes," "anticipates," "estimates," "intends," "plans," and variations of such words and similar expressions are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ are:

- Actions of federal and state regulatory bodies setting rates and implementing the restructuring of the electric utility industry, including, for example, regulatory actions in California that could affect SCE's ability to recover its past investments in utility plant and earn competitive returns.

- The effects of new laws and regulations relating to restructuring and other matters, such as pending federal legislation that would repeal or amend key statutes governing the electric industry.

- The effects of increased competition in the electric utility business and other energy-related businesses, including among other things the ability of customers to purchase energy and metering and billing services from nonutility energy service providers.

- Unpredictable weather conditions that may affect seasonal patterns of revenue collection, cause changes in demand (and prices) for electricity for heating and cooling purposes, and result in higher costs for repair or maintenance of assets.

- The values and other terms under which SCE is able either to sell or retain electric generation assets, and the associated ratemaking treatment.

- Financial market conditions such as inflation and changes in interest rates, which could affect the availability and cost of external financing.

- Power plant operation risks, including strikes, equipment failures and other issues.

- The effects of changes in tax laws, or unfavorable interpretation and application of the laws by tax authorities.

- New or increased environmental liabilities associated with power plants and other facilities or operations, resulting from changes in laws, accidents or other events.

- The ability of SCE to create and expand new businesses, such as telecommunications and other energy-related consumer products and services, and to operate such businesses profitably.

- Legal proceedings arising out of commercial disputes, property rights, personal injuries, and other circumstances.

Additional information about the risk factors listed above is contained throughout this annual report. Readers are urged to read this entire report and carefully consider the risks, uncertainties and other factors that affect SCE's business. The information contained in this report is subject to change without notice. Readers should review future reports filed by SCE with the Securities and Exchange Commission (SEC).

Competitive Environment

SCE currently operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing. In the generation sector, SCE has experienced competition from nonutility power producers and regulators are restructuring California's electric utility industry to facilitate additional competition. (See "Business — Changing Regulatory Environment" below for a description of these changes.)

Regulation

SCE's retail operations are subject to regulation by the California Public Utilities Commission (CPUC). The CPUC has the authority to regulate, among other things, retail rates, issuance of securities, and accounting practices. SCE's wholesale operations are subject to regulation by the Federal Energy Regulatory Commission (FERC). The FERC has the authority to regulate wholesale rates as well as other matters, including transmission service pricing, accounting practices, and licensing of hydroelectric projects.

SCE's transmission operations, including other generators' rights of access to SCE's transmission lines, also are subject to regulation by the California Independent System Operator (ISO), an entity that was created by the California restructuring legislation in 1996 and went into operation in 1998. The 1996 restructuring legislation also created the PX, a non-profit entity that conducts frequent electronic auctions of electricity. During an interim transitional period (ending no later than year-end 2001), SCE is required by CPUC order to sell all SCE-generated electricity to the PX and to purchase power needed for retail customers from the PX.

SCE is subject to the jurisdiction of the Nuclear Regulatory Commission (NRC) with respect to its nuclear power plants. NRC regulations govern the granting of licenses for the construction and operation of nuclear power plants and subject those power plants to continuing review and regulation.

The construction, planning, and siting of SCE's power plants within California are subject to the jurisdiction of the California Energy Commission and the CPUC. SCE is subject to the rules and regulations of the California Air Resources Board and local air pollution control districts with respect to the emission of pollutants into the atmosphere; the regulatory requirements of the California State Water Resources Control Board and regional boards with respect to the discharge of pollutants into waters of the state; and the requirements of the California Department of Toxic Substances Control with respect to handling and disposal of hazardous materials and wastes. SCE is also subject to regulation by the Environmental Protection Agency (EPA), which administers certain federal statutes relating to environmental matters. Other federal, state, and local laws and regulations relating to environmental protection, land use, and water rights also affect SCE.

The California Coastal Commission has continuing jurisdiction over the coastal permit for San Onofre Nuclear Generating Station Units 2 and 3. Although the units are operating, the permit's mitigation requirements have not yet been completed. California Coastal Commission jurisdiction may continue for several years due to implementation and oversight of permit mitigation conditions, including restoration of wetlands and construction of an artificial reef for kelp.

The Department of Energy has regulatory authority over certain aspects of SCE's operations and business relating to energy conservation, power plant fuel use and disposal, electric sales for export, public utility regulatory policy, and natural gas pricing.

On December 16, 1997, the CPUC adopted a decision which established new rules governing the relationship between California's natural gas local distribution companies, electric utilities, and certain of their affiliates. While SCE and its affiliates have been subject to affiliate transaction rules since the establishment of its holding company structure in 1988, these new rules are more detailed and restrictive. On December 31, 1997, SCE filed a preliminary compliance plan which set forth SCE's implementation of the new affiliate transaction rules. This preliminary compliance plan was supplemented by an additional filing made on January 30, 1998. In September 1998, the CPUC issued a resolution accepting certain portions of SCE's compliance plan and rejecting others. SCE filed a revised compliance plan in October 1998 as ordered. No party protested that revised plan.

The new affiliate transaction rules apply to all utility transactions, including electric utilities, with affiliates engaging in the production of products that use electricity or the providing of services that relate to the use of electricity. Edison International is not subject to these new affiliate transaction rules and continues to be subject to the prior rules. The new affiliate transaction rules are structured to address CPUC concerns regarding market power and cross-subsidization arising out of the new competitive electricity market in California. The new rules are categorized into nondiscrimination standards, disclosure and information standards, and separation standards. The new rules also set forth requirements and restrictions on the utility's offering of certain products and services.

The CPUC has modified certain of the rules in response to petitions from various parties. SCE is still awaiting CPUC decisions on its compliance plan (which includes SCE's interpretation of the rule governing affiliate use of the utility's name and logo). The CPUC decision concerning the name and logo rule may affect the disposition of a pending complaint against SCE filed by the CPUC's Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN) with the CPUC, which alleges a violation of that rule by Edison Source in a bulk mailing in 1998.

SCE has not yet been materially affected by the new affiliate transaction rules, and it expects that the rules will not materially affect its results of operation or its financial position in the future.

Changing Regulatory Environment

SCE's regulatory environment is changing as a result of a 1995 CPUC decision on restructuring and state legislation enacted in 1996. The state legislation, California Assembly Bill 1890 as amended by California Senate Bill 477 (the restructuring legislation) substantially adopted the CPUC's restructuring decision by addressing stranded-cost recovery for utilities and providing a certain cost-recovery time period for the transition costs associated with generation-related assets. The restructuring legislation also included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. The restructuring legislation mandated other rates to remain frozen at June 1996 levels (system average of 10.1¢ per kilowatt-hour), including those for large commercial and industrial customers, and included provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement during the 1998—2001 transition period. In addition, the restructuring legislation mandated the implementation of the competition transition charge (CTC) (see the detailed discussion in "Revenue and Cost-Recovery Mechanisms" below) that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring.

Rate Reduction Notes

In December 1997, after receiving approval from the CPUC and the California Infrastructure and Economic Development Bank, a limited liability company created by SCE issued approximately $2.5 billion of rate reduction notes. Residential and small commercial customers, whose 10% rate reduction began January 1, 1998, are repaying the notes over the expected ten-year term through non-bypassable charges based on electricity consumption. There were originally seven classes of notes. The first class, in the amount of $246.3 million, matured in December 1998. The remaining notes consist of six classes with scheduled maturities ranging from less than one year to eight years, with interest rates ranging from 6.14% to 6.42%.

Revenue and Cost-Recovery Mechanisms

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

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

Effective with the commencement of the ISO and PX operations on March 31, 1998, generation costs are subject to recovery through the competitive market and the CTC mechanism, which now includes the nuclear rate-making agreements. Transition cost recovery for most utility generation assets will terminate on the earlier of December 31, 2001, or when these costs are fully collected. The portion of revenue related to fossil and hydroelectric generation operations that are economic is recovered through the market. SCE's operational costs associated with its fossil and hydroelectric plants are being recovered through market revenue. The power sales revenue from fossil and hydroelectric facilities in excess of fossil operational costs and the hydroelectric revenue requirement are credited against transition costs. In 1999, fossil and hydroelectric generation assets had the opportunity to earn a 7.22% return. SCE has filed an application with the CPUC regarding the market valuation of its hydroelectric facilities. (See further discussion below.)

The portion of revenue related to fossil and hydroelectric generation operations that are made uneconomic by electric industry restructuring is recovered through the CTC mechanism. The revenue available to recover such uneconomic generation costs will be determined residually by subtracting the other rate components from the total rates. This residual revenue will first be allocated to recovery of FERC-authorized ISO charges for transmission support and for purchases from the PX, and then to recovery of transition costs. Transition costs associated with QF and interutility contracts and the acceleration of sunk cost recovery will be subject to annual reasonableness review by the CPUC.

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

In March 1997, SCE filed a transmission owners tariff with the FERC, in conjunction with tariffs filed by the ISO and PX with the FERC in March 1997. Together, these tariffs set forth the rate design and terms and conditions for transmission service provided over SCE's facilities over which the ISO will have operational control. The transmission owners tariff also sets forth SCE's proposed transmission access charge. Additionally, in March 1997, SCE filed a wholesale distribution access tariff. The FERC accepted the tariffs for filing, subject to refund, effective April 1, 1998.

With the commencement of the ISO and PX, transmission cost recovery is now under FERC authority. An administrative law judge (ALJ) decision was issued in March 1999 recommending a 9.68% return on equity for transmission assets, compared to the current CPUC return on equity for distribution facilities of 11.6%. In addition, the ALJ proposed a $23 million reduction in the proposed transmission revenue requirement relating to overhead costs, despite the fact that before implementation of the ISO, SCE had been authorized full recovery of these overhead costs in rates at the CPUC. In total, the ALJ decision would result in about a $50 million reduction annually in transmission revenue from the level proposed by SCE of $211 million. Transmission rates have reflected SCE's proposed $211 million transmission revenue requirement since they were implemented in April 1998. As a result of the retail rate freeze contained in the restructuring legislation, instead of being ordered to refund excess payments back to retail customers, SCE expects to be able to credit the amount of these payments against remaining transition costs.

SCE has opposed the ALJ decision and expects that the final FERC decision, expected in early to mid-2000, will be more favorable. In the event that SCE does not prevail on the overhead cost issue at the FERC, SCE does have the opportunity to seek recovery in distribution rates at the CPUC of any overhead costs not allowed in rates by the FERC.

As a part of compliance with the restructuring legislation, in October 1999, SCE filed an application with the CPUC to approve an auction process for its 56% interest in the Mohave Generating Station (Mohave Station). A CPUC decision on the auction process is expected in early to mid-2000.

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

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

Restructuring Implementation Costs

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

Market Risk Exposures

In July 1999, the PX introduced a block forward energy product. Participants can purchase power up to 12 months in advance in monthly blocks for six days a week and sixteen hours a day. Purchasing these blocks hedges against the risk of price spikes in the spot energy markets. SCE has been using the PX's block forward market since it received approval from the CPUC to do so in July 1999. The CPUC set purchasing limits on utility purchases of approximately 2,000 MW. In March 2000 the PX introduced additional forward block products covering different hours. The CPUC granted SCE authority to purchase these new products on March 16, 2000. Furthermore, the CPUC allowed SCE to purchase up to significantly increased limits, reaching 5,200 MW during summer when SCE's demand is at its peak. SCE thus has an increased ability to hedge against high price spikes in the energy markets. Purchases within these authorized limits will be deemed reasonable by the CPUC. The CPUC granted this authority for the duration of the rate freeze.

The PX recently requested authority from the FERC to offer additional products including block forward ancillary services. SCE has filed an Advice Letter to the CPUC requesting authority to participate in these new markets to hedge against price spikes in the ISO's ancillary service spot market. SCE expects a CPUC Decision in the first or second quarter of 2000.

Accounting for Generation-Related Assets

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

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

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

Other Rate Matters

CPUC Retail Ratemaking

The CPUC regulates the charges for services provided by SCE to its retail customers. As discussed above in the section on "Changing Regulatory Environment", the nature in which the CPUC regulates SCE is changing. The CPUC has issued final decisions regarding direct access, transition cost recovery, and rate unbundling in the restructuring of the electric industry. These decisions affected cost recovery and rate regulation, and authorized new ratemaking mechanisms which were implemented, replacing the Electric Revenue Adjustment Mechanism, Energy Cost Adjustment Clause (ECAC) and base rates mechanism (pre-restructuring ratemaking mechanisms) as of January 1, 1998.

Total rates for all customers are frozen at June 10, 1996, levels, although residential and small commercial customers have received a 10% reduction from the June 10, 1996, rate levels beginning on January 1, 1998. These rate levels will remain in effect for the remainder of the transition period. Under these frozen rates, individual rate components (distribution, transmission, nuclear decommissioning, and public purpose programs) are determined according to CPUC- or FERC-authorized mechanisms, with the generation rate determined residually by subtracting these other components from the total rate. Beginning for rates effective in 1999, the consolidation of the individual rate component changes and the calculation of the residual generation rate are set forth for CPUC approval as part of the Revenue Adjustment Proceeding (RAP). On June 1, 1998, SCE filed its first annual RAP Report in compliance with CPUC directives to: (1) consolidate authorized rates and revenue requirements associated with various proceedings and mechanisms; (2) verify the residual CTC revenue calculation in the Transition Revenue Account (TRA); (3) verify the regulatory account balances which were transferred to the Transition Cost Balancing Account (TCBA) on January 1, 1998 (See "Annual Transition Cost Proceedings" below for further discussion of the TCBA); (4) streamline certain balancing and memorandum accounts; and (5) review the PX charge/credit calculation. On June 6, 1999, the CPUC issued its final 1998 RAP decision. In compliance with that decision, SCE updated its nongeneration rate components in October 1999. To maintain overall frozen rate levels, to the extent nongeneration rate components are authorized to change, the generation rate component changes equal and opposite from the nongeneration rate component changes. The decision also instructed SCE to include in the 1999 RAP Report a PX credit calculation that reflects the long run marginal costs of customer account managers, customer service representatives, self-provision of ancillary services, and financing costs for purchasing power from the PX.

In June 1999, the CPUC issued a decision regarding unbundling SCE's cost of capital based on major utility functions. The decision was in response to SCE's May 1998 application on this issue. The CPUC found no unbundling adjustment was required in setting 1999 cost of capital for the California electric utilities. Furthermore, the CPUC ruled that SCE's rate of return should continue to be governed by the cost of capital trigger mechanism authorized as part of SCE's performance based ratemaking mechanism. (See discussion under "Revenue and Cost-Recovery Mechanisms") As a result, SCE's return on equity for 1999 was unchanged at 11.6%.

On August 9, 1999, SCE filed its 1999 RAP Report requesting CPUC approval of the following: (1) consolidation of the 2000 nongeneration revenue requirements; (2) rate levels for 2000, including the residually determined generation rates; (3) 2000 kWh sales forecast; (4) entries to the TRA for the period June 1, 1998, through May 31, 1999; (5) proposed retention, elimination, and modification of balancing and memorandum accounts; (6) implementation and costs of electric vehicle programs during the record period; (7) administration of SCE's self-generation deferral rate contracts during the record period; and (8) the proposed additional 2 cents/MWh credit to direct access customers associated with SCE's procurement of PX energy for bundled service customers. SCE anticipates a final 1999 RAP decision in the third quarter of 2000.

Nuclear Decommissioning and Public Purpose Program Rates

Recovery of SCE's nuclear decommissioning costs and legislatively mandated public purpose program funding is made through rates set to recover 100% of these costs. Public purpose programs include cost effective energy efficiency, research, renewable technology development, and low income programs.

Annual Transition Cost Proceedings (ATCP)

In 1997, the CPUC established the ATCP as the proceeding to determine whether SCE's TCBA entries are recorded pursuant to applicable CPUC decisions and the restructuring legislation, and that certain expenses are justified. The purpose of the TCBA is to provide and account for the recovery by SCE of certain costs associated with the transition to a restructured electric industry in California.

1998 ATCP

On September 1, 1998, SCE filed its first ATCP Report with the CPUC and requested, among other things, that entries made to the TCBA and applicable generation-related memorandum accounts during the record period of January 1, 1998, through June 30, 1998, be found to be justified and in compliance with applicable CPUC decisions and the restructuring legislation. On March 31, 1999, the ORA submitted its Report and made the following recommendations adverse to SCE: (1) $2.37 million in QF shareholder incentive amounts should be disallowed; (2) $3.2 million in employee-related transition costs should be disallowed; and (3) $9.67 million in post-retirement benefits other than pensions (PBOPs) and $5.76 million in long-term disability regulatory assets should be rejected. On June 14, 1999, the ALJ granted SCE's motion to strike the ORA's testimony and recommendations on the third item. Prior to hearings, the ORA and SCE recommended that the CPUC adopt a stipulation and joint recommendation whereby SCE would not recover $895,000 in retention bonuses, and $1.19 million of the total QF shareholder incentive amounts. On October 8, 1999, the matter was submitted to the CPUC.

On January 6, 2000, an ALJ issued a proposed decision adopting the stipulation and joint recommendation as specified above. In addition, the proposed decision provided clarification on the following four accounting issues impacting the operation of the TCBA: (1) It directs SCE and the other utilities to review their estimates of market value for each divested generating plant and recalculate the interest accrued on undercollections of the TCBA during the record period. SCE believes it used the market value accounting directed by the proposed decision. (2) It clarifies the accounting methodology used to estimate the market value of retained generating assets. At this time, SCE believes there will be no negative impact on earnings associated with this issue. (3) It directs SCE to apply the TCBA overcollection of $350.7 million as of June 30, 1998, to further accelerate the depreciation of those transition cost assets with the highest rate of return, and in a manner which provides the greater tax benefits (i.e., to accelerate the recovery of nuclear sunk costs). It also directs SCE to net a $238 million undercollection in the ISO/PX implementation delay memorandum account against the TCBA overcollection in the calculation. SCE estimates a $10 million impact over the entire transition period ending December 31, 2001, if this accounting change is adopted by the CPUC. (4) It disallows the recovery through the TCBA for the record period of certain telecommunications, training, mechanical service shop and warehouse equipment that were related to SCE's divested generating plants but was not purchased by the new owners. The net book value of these retained assets is in the $8 million to $10 million range. Comments to the proposed decision were filed in January and a supplemental brief was filed on February 1, 2000.

On February 17, 2000, the ALJ prepared a revised proposed decision that addressed these four matters and left intact other provisions of the proposed decision. The revised proposed decision was approved by the CPUC on the same day. The decision found that SCE's calculation of the TCBA for the record period was correct and that SCE appropriately applied the overcollection as of June 30, 1998, to the subsequent undercollection. Therefore, the decision does not require SCE to accelerate recovery of its nuclear assets. The decision changes the accounting methodology used to estimate the market value of retained generating assets and requires that SCE credit the TCBA for the aggregate net book value of SCE's non-nuclear assets, including the land surrounding such assets. SCE's share of the Mohave Station and Four Corners Generating Station (Four Corners) are excluded from this requirement. Ongoing depreciation, taxes, and return will be recovered through market revenue. The decision disallows the recovery through the TCBA for the record period of the retained assets but does not preclude SCE from seeking recovery in future record periods. The disallowance for the 1998 record period was $55,000.

On February 29, 2000, SCE made a request to the CPUC's Executive Director for an extension of time to file the compliance advice letter so that the CPUC could review SCE's soon-to-be filed petition for a stay of the decision, application for rehearing and/or petition for modification of the decision. In a letter dated March 3, 2000, the Executive Director granted SCE an extension of time until May 31, 2000, to file its advice letter compliance filing. At this time, SCE believes there will be no materially negative impact on earnings.

1999 ATCP

On September 1, 1999, SCE filed its 1999 ATCP setting forth entries made to the TCBA and other generation-related accounts for the months of July 1998 through June 1999. The purpose of the ATCP is to ensure the recovery of generation-related transition costs through the TCBA that complies with the guidelines established by the CPUC. The TCBA tracks the recovery of transition costs, including the accelerated recovery of plant balances, QF and purchased power costs, and regulatory assets and obligations. On February 23, 2000, the ORA issued its report and made the following recommendations adverse to SCE: (1) approximately $5 million in post record period adjustments booked after the date of divestiture for capital additions made in 1996 to divested fossil generating plants; (2) $17.2 million related to the termination contract with the Sacramento Municipal Utility District; (3) $147,000 in employee-related transition costs; and (4) an $136,000 adjustment to the QF subaccount of the TCBA. SCE will serve rebuttal testimony on March 29, 2000, and supplemental testimony on April 3, 2000.

Annual Energy Cost Adjustment Clause Proceedings

Through 1998, SCE filed ECAC applications each year with the CPUC regarding its fuel and purchased power expenses, seeking the CPUC's determination that SCE's fuel and purchased power costs, including payments to QFs, were reasonable. These matters are respectively referred to herein as "non-QF matters" and "QF matters."

QF MATTERS

The ORA issued its report on the 1998 ECAC period on February 19, 1999. The ORA did not identify any reasonableness issues associated with SCE's QF activities during the 1998 period. On November 4, 1999, the CPUC issued its decision approving all of SCE's QF administrative matters in the 1998 ECAC. The 1998 ECAC is SCE's last ECAC application.

NON-QF MATTERS

1997 Annual ECAC Record Period

On May 30, 1997, SCE filed its annual reasonableness report requesting that the CPUC find reasonable its fuel and purchased-power costs recorded during the period of April 1, 1996, through March 31, 1997.

The ORA's review of the non-QF operations and costs was consolidated with its review of the non-QF operations and costs for the 1996 ECAC record period. The ORA filed its report on August 18, 1997. In its report, the ORA recommended, among other things: 1) a disallowance of $360,000 associated with an outage at the coal-fired Four Corners; 2) a $200,000 adjustment to the costs recorded in SCE's Catastrophic Events Memorandum Account, and 3) a determination that SCE's execution of its natural gas transportation contract with Southwest Gas Corporation be found unreasonable for purposes of CTC eligibility. The January 1998 hearings resulted in a CPUC decision issued on October 22, 1998, adopting the proposed disallowances. The decision found the execution of the Southwest Gas contract reasonable and, therefore, any uneconomic costs associated with the contract are to be subject to CTC recovery. The remainder of SCE's non-QF costs and expenses were also found reasonable.

On December 21, 1998, SCE filed a petition for modification of the above decision alleging that it erroneously stated that SCE may seek recovery of its Nuclear Unit Incentive Procedure (NUIP) rewards in the RAP. The CPUC found that SCE's calculation of the NUIP reward was reasonable and it was an error for the CPUC to order another reasonableness review of these rewards which totaled $15.2 million plus interest. The February 18, 1999, CPUC decision granted SCE's petition to modify the 1998 decision and authorized the booking of the NUIP rewards into the TCBA.

1998 Annual ECAC Record Period

On February 19, 1999, the ORA issued its reasonableness report on the 1998 ECAC period and made the following recommendations. The ORA found that SCE's costs ($239.1 million) recorded in the ISO/PX Implementation Delay Memorandum Account (IPDMA) properly reflected the ISO/PX expenses that accrued during the three month delay in the commencement of ISO/PX operations. The ORA also required SCE to include a showing that it undertook all practicable steps to minimize the delay with its request for the recovery of IPDMA costs. The ORA found no evidence to show that SCE caused a delay in the ISO/PX implementation. The ORA recommended two coal generation related disallowances seeking replacement fuel costs based on December 1997 outages of Mohave Station Units 1 and 2 in the amount of $2.4 million, and a $15.7 million disallowance related to an outage at Four Corners Unit 5. The ORA also recommended disallowances totaling $5.6 million plus interest, to correct for audit errors. Hearings were held in June 1999 and on September 20, 1999, a CPUC ALJ issued a proposed decision that rejected the ORA's recommended disallowances for the outages at Four Corners and the Mohave Station, but adopted the ORA's recommended balancing account adjustment. A CPUC decision issued on November 4, 1999, adopted the ALJ's proposed decision without change.

Palo Verde Nuclear Generating Station

In January 1997, the CPUC authorized a further acceleration of the recovery of SCE's remaining investment of $1.2 billion in Palo Verde Units 1, 2, and 3. The accelerated recovery will continue through December 2001, earning a 7.35% fixed rate of return. The future operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are subject to balancing account treatment through 2001. Beginning January 1, 1998, the balancing account became part of the CTC mechanism. The existing NUIP will continue only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle. Beginning in 2002, SCE will be required to share the net benefits received from the operation of Palo Verde equally with ratepayers.

San Onofre Nuclear Generating Station Units 2 and 3

In April 1996, the CPUC authorized a further acceleration of the recovery of SCE's remaining investment of $2.6 billion in San Onofre Units 2 and 3. The accelerated recovery will continue through December 2001, earning a 7.35% fixed rate of return. San Onofre's operating costs, including nuclear fuel, nuclear fuel financing costs, and incremental capital expenditures, are recovered through an incentive pricing plan which allows SCE to receive about 4¢ per kWh through December 31, 2003. Beginning January 1, 1998, the accelerated plant recovery and incremental cost incentive pricing became part of the CTC mechanism. Beginning in 2004, SCE will be required to share the benefits received from operation of San Onofre Units 2 and 3 equally with ratepayers.

New Accounting Rules

An accounting rule, which requires that costs related to start-up activities be expensed as incurred, became effective January 1, 1999. This new accounting rule did not materially affect SCE's results of operations or its financial position.

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

Fuel Supply and Purchased Power Costs

Since April 1, 1998, SCE has been required to purchase all power for distribution to retail customers from the PX. In 1999, fuel and purchased-power costs, including net PX purchases, were approximately $3.4 billion, which was a 5% decrease from the costs in 1998.

SCE's sources of energy during 1999 were as follows: 58.9% purchased power; 22.0% nuclear; 13.5% coal; and 5.6% hydro.

Average fuel costs, expressed in ¢ per kWh, for the year ended December 31, 1999, were: oil, 7.51¢; nuclear, 0.41¢; and coal, 1.23¢.

Natural Gas Supply

As a result of the sale of all of its gas-fired generating stations, SCE has terminated four long-term natural gas supply and three long-term gas transportation contracts which had been used to import gas from Canada. In addition, SCE has exercised an option under its 15-year gas transportation commitment with El Paso Natural Gas Company to reduce its capacity obligation from 200 million to 130 million cubic feet per day.

Nuclear Fuel Supply

SCE has contractual arrangements covering 100% of the projected nuclear fuel requirements for San Onofre through the years indicated below:

Uranium concentrates(*)	2003
Conversion	2003
Enrichment	2003
Fabrication	2005

(*) Assumes the San Onofre participants meet their supply obligations in a timely manner.

Assuming normal operation and full utilization of existing on-site storage capacity, San Onofre Units 2 and 3 will maintain full-core offload reserve through 2005. The Nuclear Waste Policy Act of 1982 requires that the United States Department of Energy provide for the disposal of utility spent nuclear fuel beginning January 31, 1998. The Department of Energy has defaulted on its obligation to begin acceptance of spent nuclear fuel from the commercial nuclear industry by that date. Additional spent fuel storage either on-site or at another location will be required to permit continued operations beyond 2005.

Participants at Palo Verde have contractual agreements for uranium concentrates to meet projected requirements through 2000. Independent of arrangements made by other participants, SCE will furnish its share of uranium concentrates requirement through at least 2000 from existing contracts. Contracts covering 100% requirements are in place for conversion through 2000, enrichment through 2002, and fabrication through 2016.

Assuming normal operation and regulatory approval for more condensed on-site spent fuel storage, Palo Verde will maintain full-core offload reserve until the fall of 2003 for Unit 2 and spring and fall of 2004 for Units 1 and 3, respectively. Arizona Public Service, operating agent for Palo Verde, has commenced construction of an interim fuel storage facility that it projects will be completed in 2002.

Environmental Matters

Legislative and regulatory activities in the areas of air and water pollution, waste management, hazardous chemical use, noise abatement, land use, aesthetics, and nuclear control continue to result in the imposition of numerous restrictions on SCE's operation of existing facilities, on the timing, cost, location, design, construction, and operation by SCE of new facilities, and on the cost of mitigating the effect of past operations on the environment. These activities substantially affect future planning and will continue to require modifications of SCE's existing facilities and operating procedures. SCE is unable to predict the extent to which additional regulations may affect its operations and capital expenditure requirements.

In California, pursuant to federal, state and regional Clean Air Act programs, SCE generating stations were required to reduce emissions of oxides of nitrogen and certain other pollutants. During 1998, SCE sold all of its oil- and gas-fueled generating stations within the Mohave Desert Air Quality Management District, Ventura County Air Pollution Control District, and in the Santa Barbara County Air Pollution Control District. SCE has sold all but one of its oil- and gas-fired generating stations within the South Coast Air Quality Management District. The remaining plant, the small diesel-fired Pebbly Beach Generating Station, supplies power to Santa Catalina Island. After the sale of its oil- and gas-fueled generating stations, SCE commenced operation of the facilities under operation and maintenance contracts with the individual owners except for two plants that ceased operation during 1998. SCE will continue to operate those divested facilities as active generating stations for the required two-year period specified by California's electric utility restructuring legislation. SCE's operation of the stations under these operation and maintenance contracts is at the direction and expense of the new owners. SCE is responsible for maintaining the environmental permits for the plants. Among other responsibilities, the new owners, not SCE, are responsible for the purchase and installation of emissions control equipment, and for obtaining trading credits required for the plants under the Regional Clean Air Incentives Market within the South Coast Air Quality Management District.

SCE also owns a 56% undivided interest in the Mohave Generating Station (Mohave Station) located in Laughlin, Nevada, which is subject to certain air quality programs. Several recent developments affect the emission reduction requirements for this facility. Probably the most significant development is the entry of a consent decree voluntarily entered into among certain environmental organizations and the owners of the Mohave facility. This decree resolved a litigation filed on February 19, 1998, by the Sierra Club and the Grand Canyon Trust in the U.S. District Court in Nevada against the facility owners alleging violations of the Nevada State Implementation Plan and applicable air quality permits related to opacity and sulfur dioxide emission limits. (See, "Mohave Generating Station Environmental Litigation," under Item 3 below for additional discussion.) The decree, which was approved by the Court in December 1999, was designed also to address concerns raised by two EPA programs regarding visibility and regional haze. The EPA issued its final rulemaking regarding regional haze regulations on July 1, 1999. The final rule is not expected to impose any additional emissions control requirements on the Mohave Station beyond meeting the provisions of the consent decree. The EPA and SCE also participated in a study to determine the specific impact of air contaminant emissions from the Mohave Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave Station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave Station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. Finally, in June, 1999, the EPA issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. SCE filed comments on the proposed rulemaking in November 1999. In a letter to SCE, the EPA has expressed its belief that the controls provided in the consent decree will likely resolve the potential Clean Air Act visibility concerns. The Agency is considering incorporating the decree into the visibility provisions of its Federal Implementation Plan for Nevada.

The Clean Air Act also requires the EPA to carry out a three-year study of risk to public health from the emissions of toxic air contaminants from electric utility steam generating plants, and to regulate such emissions if the Administrator makes certain findings. The study's final report to Congress concluded that mercury from coal-fired utilities is the hazardous air pollutant of greatest potential concern and merits additional research and monitoring to better understand the risks of mercury exposure. Other pollutants that may potentially need further study are dioxins and arsenic from coal-fired plants, and nickel from oil-fired plants. The EPA concluded that the impacts from emissions from gas-fired utilities are negligible and that there is no need for further evaluation of the risks of hazardous air pollutants emitted from such plants.

Regulations under the Clean Water Act require permits for the discharge of certain pollutants into U.S. waters. Under this act, the EPA issues effluent limitation guidelines, pretreatment standards, and new source performance standards for the control of certain pollutants. Individual states may impose more stringent limitations. SCE incurs additional expenses and capital expenditures in order to comply with guidelines and standards applicable to steam electric power plants. SCE presently has discharge permits for all applicable facilities.

The Safe Drinking Water and Toxic Enforcement Act prohibits the exposure to individuals of chemicals known to the State of California to cause cancer or reproductive harm and the discharge of such listed chemicals into potential sources of drinking water. Additional chemicals are continuously being put on the state's list, requiring constant monitoring.

The Resource Conservation and Recovery Act provides the statutory authority for the EPA to implement a regulatory program for the safe treatment, recycling, storage, and disposal of solid and hazardous waste. An unresolved issue remains regarding the degree to which coal waste should be regulated under the act. Increased regulation may result in increased expenses relating to the operation of the Mohave Station.

The Toxic Substances Control Act and accompanying regulations govern the manufacturing, processing, distribution in commerce, use, and disposal of listed compounds, such as polychlorinated biphenyls, a toxic substance used in certain electrical equipment. Current costs for disposal of this substance are immaterial.

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 discounted amounts).

SCE's recorded estimated minimum liability to remediate its 45 identified sites is $163 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: (1) the extent and nature of contamination; (2) the scarcity of reliable data for identified sites; (3) the varying costs of alternative cleanup methods; (4) developments resulting from investigatory studies; (5) the possibility of identifying additional sites; and (6) the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $284 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas- and oil-fueled generation plants (except the Pebbly Beach Generating Station) and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 42 of its sites, representing $90 million of its recorded liability, through an incentive mechanism (SCE may seek to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $126 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $5 million to $15 million. Recorded costs for 1999 were $14 million.

Based on currently available information, SCE believes that it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or its financial position. There is 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.

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

Year 2000 Issue

SCE implemented a comprehensive program to address potential Year 2000 computer system impacts, consisting of five phases: inventory, impact assessment, remediation, testing and implementation. Edison International provided overall coordination of this effort, working with SCE and its business units. SCE met its goal to have 100% of its critical systems Year 2000-ready by July 1, 1999. A critical system was defined as those applications and systems, including embedded processor technology, which if not appropriately remediated, may have had a significant impact on customers, the health and safety of the public and/or personnel, the revenue stream, or regulatory compliance. SCE developed Year 2000-related contingency plans, which were in place at year-end 1999.

None of SCE's critical applications or assets encountered significant problems on or since January 1, 2000, including on and over February 29, 2000, and they continue to operate as expected. SCE expects business as usual in 2000, as it relates to its Year 2000 computer systems issues.

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

Item 2. Properties

Existing Generating Facilities

SCE owns and operates one diesel-fueled generating plant located on Santa Catalina island, 37 hydroelectric plants, and an undivided 75.05% interest (1,614 MW net) in San Onofre Units 2 and 3. These plants are located in Central and Southern California.

SCE also owns a 15.8% (590 MW net) share of Palo Verde which is located near Phoenix, Arizona. SCE owns a 48% undivided interest (754 MW net) in Units 4 and 5 at the Four Corners, which is a coal-fueled steam electric generating plant located in New Mexico. Palo Verde and Four Corners are operated by other utilities. SCE operates and owns a 56% undivided interest (885 MW) in the Mohave Station, which consists of two coal-fueled steam electric generating units in Clark County, Nevada. At year-end 1999, the existing SCE-owned generating capacity (summer effective rating) was divided approximately as follows: 44.2% nuclear, 32.4% coal, 23.2% hydroelectric, and 0.2% diesel. Pursuant to California's restructuring legislation, SCE filed an application with the CPUC on October 14, 1999, seeking authority to hold an auction to sell SCE's ownership interest in the Mohave Station. A CPUC decision on the auction process is expected in early to mid-2000.

San Onofre, Four Corners, certain of SCE's substations and portions of its transmission, distribution and communication systems are located on lands of the U. S. or others under (with minor exceptions) licenses, permits, easements or leases, or on public streets or highways pursuant to franchises. Certain of such documents obligate SCE, under specified circumstances and at its expense, to relocate transmission, distribution, and communication facilities located on lands owned or controlled by federal, state, or local governments.

The 37 hydroelectric plants (some with related reservoirs) have an effective operating capacity of 1,156 MW, and are, with five exceptions, located in whole or in part on lands of the U.S. pursuant to, 30- to 50-year governmental licenses that expire at various times between 1999 and 2029. Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire projects upon payment of specified compensation. When existing licenses expire, the FERC has the authority to issue new licenses to third parties, but only if their license application is superior to SCE's and then only upon payment of specified compensation to SCE. Any new licenses issued to SCE are expected to be issued under terms and conditions less favorable than those of the expired licenses. SCE's applications for the relicensing of certain hydroelectric projects with an aggregate effective operating capacity of 113.32 MW are pending. Annual licenses have been issued to SCE hydroelectric projects that are undergoing relicensing and whose long-term licenses have expired. The annual licenses will be renewed until the long-term licenses are issued. SCE filed an application with the CPUC on December 15, 1999, seeking authorization to market value and retain the ownership and operation of the hydroelectric plants pursuant to the state's electric industry restructuring legislation.

The capacity factors in 1999 for SCE's principal generation resources were: 43.3% for SCE's hydroelectric plants (lower than average due to below-normal water conditions); 88.4% for San Onofre; 70.8% for the Mohave Station; 79.4% for Four Corners Units 4 and 5; and 93% for Palo Verde.

Substantially all of SCE's properties are subject to the lien of a trust indenture securing First and Refunding Mortgage Bonds (Trust Indenture), of which approximately $2.2 billion in principal amount was outstanding on December 31, 1999. Such lien and SCE's title to its properties are subject to the terms of franchises, licenses, easements, leases, permits, contracts, and other instruments under which properties are held or operated, certain statutes and governmental regulations, liens for taxes and assessments, and liens of the trustees under the Trust Indenture. In addition, such lien and SCE's title to its properties are subject to certain other liens, prior rights and other encumbrances, none of which, with minor or unsubstantial exceptions, affect SCE's right to use such properties in its business, unless the matters with respect to SCE's interest in Four Corners and the related easement and lease referred to below may be so considered.

SCE's rights in Four Corners, which is located on land of The Navajo Nation of Indians under an easement from the U. S. and a lease from The Navajo Nation, may be subject to possible defects. These defects include possible conflicting grants or encumbrances not ascertainable because of the absence of, or inadequacies in, the applicable recording law and the record systems of the Bureau of Indian Affairs and The Navajo Nation, the possible inability of SCE to resort to legal process to enforce its rights against The Navajo Nation without Congressional consent, possible impairment or termination under certain circumstances of the easement and lease by The Navajo Nation, Congress, or the Secretary of the Interior, and the possible invalidity of the Trust Indenture lien against SCE's interest in the easement, lease, and improvements on Four Corners.

Construction Program and Capital Expenditures

Cash required by SCE for its capital expenditures totaled $984 million in 1999, $861 million in 1998 and $685 million in 1997. Construction expenditures for the 2000—2004 period are forecasted at $4.8 billion.

In addition to cash required for construction expenditures for the next five years as discussed above, $2.4 billion is needed to meet requirements for long-term debt maturities and sinking fund redemption requirements.

SCE's estimates of cash available for operations for the five years through 2004 assume, among other things, the receipt of adequate and timely rate relief and the realization of its assumptions regarding cost increases, including the cost of capital. SCE's estimates and underlying assumptions are subject to continuous review and periodic revision.

The timing, type, and amount of all additional long-term financing are also influenced by market conditions, rate relief, and other factors, including limitations imposed by SCE's Articles of Incorporation and Trust Indenture.

Nuclear Power Matters

SCE's nuclear facilities have been reliable sources of inexpensive, non-polluting power for SCE's customers for more than a decade. Throughout the operating life of these facilities, SCE's customers have supported the revenue requirements of SCE's capital investment in these facilities and for their incremental costs through traditional cost-of-service ratemaking.

In 1996, the CPUC adopted SCE's San Onofre Unit 2 and 3 proposal under which SCE would have recovered its remaining investment in the San Onofre Units at a reduced rate of return of 7.35%, but on an accelerated basis during the eight-year period from the effective date in 1996 through December 31, 2003. California's restructuring legislation, however, requires the recovery of the San Onofre investment to be completed by December 31, 2001. In addition, the traditional cost-of-service ratemaking for San Onofre Units 2 and 3 was superseded by an incentive pricing plan in which SCE's customers pay a preset price for each kWh of energy generated at San Onofre during the eight-year period. The restructuring legislation allows for the continuation of the incentive pricing plan through December 31, 2003. SCE was compensated for the incremental costs required for the continued operation of San Onofre Units 2 and 3 with revenue earned through the incentive pricing plan. SCE also retained the ability to request recovery of the cost of fuel consumed for generation of replacement energy for periods in which San Onofre will not generate power through ECAC filings and, beginning in 1998, as part of ATCP. The restructuring legislation also allows SCE to continue to collect funds for decommissioning expenses through traditional ratemaking treatment.

On July 16, 1997, the CPUC approved SCE's request to transfer the recorded net investment in San Onofre Units 2 and 3 step-up transformers to San Onofre Units 2 and 3 sunk costs for recovery by December 31, 2001, at a reduced rate of return of 7.35%.

On August 21, 1997, the CPUC approved San Diego Gas & Electric's (SDG&E) and SCE's Joint Petition to Modify, requesting continued recovery of certain corporate administrative and general costs allocable to San Onofre Units 2 and 3, at rates of 0.28¢ and 0.21¢ per kWh, respectively, for the period January 1, 1998, through December 31, 2003.

In 1996, SCE filed its Palo Verde Proposal Application requesting adoption of a new rate mechanism for Palo Verde consistent with that of San Onofre Units 2 and 3. On November 15, 1996, SCE, the ORA, and TURN entered into a settlement agreement, which was approved by the CPUC on December 20, 1996. The agreement allows SCE to recover its remaining investment in the Palo Verde units by December 31, 2001, at a reduced rate of return of 7.35% consistent with the restructuring legislation. The settling parties agreed that SCE would recover its share of Palo Verde incremental operating costs, except if those costs exceed 95% of the levels forecast by SCE in its application by more than 30% in any given year. In such cases, SCE must demonstrate that the aggregate amount of the costs exceeding the forecast in that year are reasonable. If the annual Palo Verde site gross capacity factor is less than 55% in a calendar year, SCE will bear the burden of proof to demonstrate that the site's operations causing the gross capacity factor to fall below 55% were reasonable in that year. If operations are determined to be unreasonable by the CPUC, SCE's replacement power purchases associated with that period of Palo Verde operations below 55% gross capacity factor may be disallowed.

Beginning in 2002, the net benefits of future operation of Palo Verde Units 1, 2, and 3 will be shared equally between shareholders and customers. Likewise, beginning in 2004, the benefits of future operation of San Onofre Units 2 and 3 will be shared equally between shareholders and customers.

San Onofre Nuclear Generating Station

In 1992, the CPUC approved a settlement agreement between SCE and the ORA to discontinue operation of Unit 1 at the end of its then-current fuel cycle. 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. On December 21, 1998, SCE filed an application with the CPUC requesting authorization to access its nuclear decommissioning trust funds for Unit 1 for the purpose of commencing decommissioning of Unit 1 in 2000. On March 8, 1999, SCE, SDG&E, the ORA and TURN entered into a settlement agreement that provided for SCE to access its nuclear decommissioning trust funds for Unit 1 decommissioning. On June 3, 1999, the CPUC adopted the settlement agreement. On December 6, 1999, SCE applied for a coastal permit to demolish and remove San Onofre Unit 1 buildings and other structures and to construct a temporary used fuel storage facility, also referred to as an independent spent fuel storage installation, as part of the San Onofre Unit 1 decommissioning project. On February 15, 2000, the California Coastal Commission approved SCE's application. Decommissioning of Unit 1 is now underway and it is anticipated that decommissioning will continue through 2008. At that time, San Onofre Unit 1 will be completely dismantled and only the spent nuclear fuel will remain on-site in an independent spent fuel storage installation. All of SCE's reasonable San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

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

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

Palo Verde Nuclear Generating Station

Based on the latest available data, Arizona Public Service (APS), the operator of Palo Verde, estimates that the Unit 1 and Unit 3 steam generators should operate for the 40-year licensed operating life of those units, although APS continues to monitor the situation. Installation of new steam generators in Unit 2 has been approved by the participants and is planned for 2003. APS has indicated to the participants that it believes that replacement of the Unit 2 steam generators would cost between $100 million and $150 million. SCE estimates that this cost could be higher, such that its share of this cost would be between $16 million and $30 million plus replacement power costs.

Nuclear Facility Decommissioning

Decommissioning of San Onofre Unit 1 commenced in 1999 (See "San Onofre Nuclear Generating Station" above for additional discussion). On March 9, 2000, the NRC amended the operating licenses for San Onofre Units 2 and 3 to allow both units to operate through 2022. Prior to this amendment, the NRC operating licenses for San Onofre allowed both units to operate through 2013. SCE plans to decommission San Onofre Units 2 and 3 in 2013 and Palo Verde at the end of each unit's operating license by a removal method authorized by the NRC. The San Onofre Units 2 and 3 and Palo Verde operating licenses currently expire in 2022 and 2028, respectively. Decommissioning is estimated to cost $2.0 billion in current-year dollars based on site-specific studies performed in 1998 for San Onofre and Palo Verde. This estimate considers the total cost of decommissioning and dismantling the plant, including labor, material, burial, and other costs. The site-specific studies are updated approximately every three years. 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.

Decommissioning expense was $124 million in 1999 and $164 million in 1998. The accumulated provision for decommissioning was $1.3 billion at December 31, 1999, and $1.2 billion at December 31, 1998. The estimated costs to decommission San Onofre Unit 1 ($360 million in 1998 dollars) 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.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the U.S. results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $88 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $175 million per nuclear incident. It would have to pay, however, 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 by a mutual insurance company owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $19 million per year. Insurance premiums are charged to operating expense.

Item 3. Legal Proceedings

Geothermal Generators' Litigation

On June 9, 1997, SCE filed a complaint in Los Angeles County Superior Court against an independent power producer of geothermal generation and six of its affiliated entities (Coso parties). SCE alleges that in order to avoid power production plant shutdowns caused by excessive noncondensable gas in the geothermal field brine, the Coso parties routinely vented highly toxic hydrogen sulfide gas from unmonitored release points beginning in 1990 and continuing through at least 1994, in violation of applicable federal, state, and local environmental law. According to SCE, these violations constituted material breaches by the Coso parties of their obligations under their contracts with SCE and applicable law. SCE seeks damages for excess power purchase payments made to the Coso parties and other relief. The Coso parties' motion to transfer venue to Inyo County Superior Court was granted on August 31, 1997.

The Coso parties filed a cross-complaint against SCE, The Mission Group, and Mission Power Engineering Company (Mission parties), which contains claims for breach of contract, unfair competition, interference with contract, defamation, breach of an earlier settlement agreement between the Mission parties and the Coso parties, and other claims. As against SCE, the cross-complaint seeks restitution, compensatory damages in excess of $115 million, punitive damages in an amount not less than $400 million, interest, attorney's fees, declaratory relief, and injunctive relief. As against the Mission parties, the cross-complaint seeks damages for breach of warranty of authority with respect to the settlement agreement, and for equitable indemnity. Edison International was named as a cross-defendant, allegedly as an alter ego of SCE and the Mission parties. The Coso parties voluntarily dismissed the claims against Edison International.

Three of the Coso Parties also filed a separate action in the Inyo County Superior Court against SCE and Edison International, alleging claims for unfair competition, false advertising and for violations of Public Utilities Code § 2106, and seeking injunctive relief, restitution, and punitive damages. The Court ordered this action consolidated with the SCE action.

Effective February 8, 2000, the parties entered into confidential agreements resolving all claims in the consolidated action and calling for dismissals with prejudice and releases. The settlement is subject to the approval of the CPUC. On February 10, 2000, the Court approved a stipulation staying all proceedings during the period required to obtain CPUC approval. SCE is in the process of preparing an application to obtain such approval. The settlement is not expected to have a material financial effect on SCE.

San Onofre Personal Injury Litigation

SCE is actively involved in three lawsuits claiming personal injuries allegedly resulting from exposure to radiation at San Onofre. On August 31, 1995, the wife and daughter of a former San Onofre security supervisor sued SCE and SDG&E in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering and the Institute of Nuclear Power Operations as defendants. All trial court proceedings were stayed pending ruling of the Ninth Circuit Court of Appeal, on an appeal of a lower court's judgment in favor of SCE in two earlier cases raising similar allegations. On May 28, 1998, the Court of Appeal affirmed these judgments. Pursuant to an agreement of the parties as described below, all proceedings in this matter have been stayed.

On November 17, 1995, an SCE employee and his wife sued SCE in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering. The trial in this case resulted in a jury verdict for both defendants. The plaintiffs' motion for a new trial was denied. Plaintiffs filed an appeal of the trial court's judgment to the Ninth Circuit Court of Appeal. Briefing on the appeal was completed in January 1999, oral argument took place on February 10, 2000, and the matter was taken under submission. A decision is not expected until spring or early summer of 2000.

On November 28, 1995, a former contract worker at San Onofre, her husband, and her son, sued SCE in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering. On August 12, 1996, the Court dismissed the claims of the former worker and her husband with prejudice, leaving only the son as plaintiff. Pursuant to an agreement of the parties as described below, all proceedings in the matter have been stayed.

In March of 1999, SCE reached an agreement with the plaintiffs in both of the cases at the U.S. District Court level to stay all proceedings including trial, pending the results of the case currently before the Ninth Circuit Court of Appeal. The parties agreed that if the plaintiffs do not receive a favorable determination on appeal then the two cases at the District Court level will be dismissed. If, however, those plaintiffs receive a favorable determination on their appeal, then the two District Court cases will be set for trial. On March 23, 1999, the District Court approved the parties' stay agreement in both cases.

SCE was previously involved, along with other defendants, in two earlier cases raising allegations similar to those described above. Although SCE is no longer actively involved in these actions, the impact on SCE, if any, from further proceedings in those cases against the remaining defendants cannot be determined at this time.

Mohave Generating Station Environmental Litigation

On February 19, 1997, the Sierra Club and the Grand Canyon Trust filed suit in the U.S. District Court of Nevada against SCE and the other three co-owners of the Mohave Station. The lawsuit alleged that the Mohave Station has been violating various provisions of the Clean Air Act, the Nevada State Implementation Plan, certain EPA orders, and applicable pollution permits relating to opacity and sulfur dioxide emission limits over the last five years. The plaintiffs sought declaratory and injunctive relief as well as civil penalties. The Clean Air Act calls for a maximum civil penalty of $25,000 per day per violation. SCE and the co-owners obtained an extension to respond to the complaint pending the court's ruling on a motion to dismiss filed by the defendants. The plaintiffs filed an opposition to the defendants' motion to dismiss as well as a separate motion for partial summary judgment on May 8, 1998.

On June 4, 1998, the plaintiffs served SCE and the other Mohave Station co-owners with a 60-day supplemental notice of intent to sue. This supplemental notice identified additional causes of action as well as an additional plaintiff (National Parks and Conservation Association) to be added to the proceedings. On November 12, 1998, the court bifurcated the liability and damage phases of the case and granted plaintiffs' motion to amend the complaint to add the National Parks and Conservation Association as a plaintiff.

On December 8, 1998, defendants filed a supplemental memorandum in support of defendants' opposition to plaintiffs' motion for partial summary judgment. On February 4, 1999, plaintiffs filed their first amended complaint to add the National Parks and Conservation Association as a plaintiff in the action. On March 10, 1999, defendants filed a motion for partial summary judgment. On March 11, 1999, plaintiffs filed a motion for partial summary judgment to establish emission limit violations as alleged in certain of the causes of action in their first amended complaint.

On March 8, 1999, the parties filed a stipulated request for a 60-day stay which was granted and ordered, by the Court on March 9, 1999. A subsequent stay was granted, which was to expire on July 6, 1999, before being extended to July 20, 1999. On July 6, 1999, each party filed an opposition to the other parties' motion for summary judgment. On August 2, 1999, defendants filed a reply to plaintiffs' opposition. On August 5, 1999, plaintiffs filed a reply to defendant's opposition.

On October 6, 1999, the parties filed a consent decree with the Federal District Court in Las Vegas, requesting the judge to approve the decree, and simultaneously dismiss the lawsuit. The decree provides that certain environmental control hardware (lime spray dryers, fabric filter baghouses and low NOx burners) should be installed on the facility by December 31, 2005, or else the Mohave Station will not be able to operate as a coal-fired facility after such date. The consent decree was signed by the court on December 15, 1999.

Navajo Nation Litigation

On June 18, 1999, SCE, was served with a complaint filed by the Navajo Nation in the United States District Court for the District of Columbia against Peabody Holding Company and certain of its affiliates (Peabody), Salt River Project Agricultural Improvement and Power District, and SCE. The complaint asserts claims against the defendants for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. Peabody supplies coal from mines on Navajo Nation lands to the Mohave Station. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants have filed motions to dismiss.

The Navajo Nation had previously filed suit in the Court of Claims against the United States Department of Interior, alleging that the Government had breached its fiduciary duty concerning the above-referenced contract negotiations. On February 4, 2000 the Court of Claims issued a decision in the Government's favor, finding that while there had been a breach, there was no available redress from the Government. In its decision, the Court indicated that it was making no statements regarding, or findings in, the above federal civil court action. On February 28, 2000, the Hopi Tribe filed a motion to intervene in the pending litigation, alleging that the royalty payments set for their interest in the coal leases with Peabody had been impacted by the events at issue in the Navajo case. The defendants filed an opposition to the motion, which has not been calendared for hearing.

Claims Arising from Oil Spill Incidents

In mid 1999, the San Bernardino County Fire Department and the Santa Ana branch of the Regional Water Quality Control Board initiated an investigation into an incident occurring on December 9, 1998, involving an oil spill at SCE's Kimberly Pole Top Station caused by severe windstorms. During the course of this investigation, the agencies discovered that barrels of mislabeled waste had remained for several days on the site of a separate oil spill and clean-up caused by an oil release from a padmount transformer.

In February 2000, SCE entered into a settlement agreement with the agencies for claims arising out of both of these incidents. SCE paid $300,000 to San Bernardino County and $100,000 to the Regional Board in civil penalties. The County also recovered its costs of $5,400 and SCE agreed to provide all elementary and middle schools in the County with an environmental education program. The estimated cost of this program is $140,000.

Item 4. Submission of Matters to a Vote of Security Holders

Inapplicable

Pursuant to Form 10-K's General Instruction (General Instruction) G(3), the following information is included as an additional item in Part I:

Executive Officers[1] of the Registrant

Executive Officer	Age at December 31, 1999	Company Position
Stephen E. Frank	58	Chairman of the Board, President, Chief Executive Officer and Director
Harold B. Ray	59	Executive Vice President, Generation Business Unit
Pamela A. Bass	52	Senior Vice President, Customer Service Business Unit
John R. Fielder	54	Senior Vice President, Regulatory Policy and Affairs
Richard M. Rosenblum	49	Senior Vice President, T&D Business Unit
Bruce C. Foster	47	Vice President, Regulatory Affairs
Thomas M. Noonan	48	Vice President and Controller
Stephen E. Pickett	49	Vice President and General Counsel
W. James Scilacci	44	Vice President and Chief Financial Officer
Anthony L. Smith	51	Vice President, Tax

(1) Executive Officers are defined by Rule 3b-7 of the General Rules and Regulations under the Securities Exchange Act of 1934, as amended.

None of SCE's executive officers are related to each other by blood or marriage. As set forth in Article IV of SCE's Bylaws, the elected officers of SCE are chosen annually by and serve at the pleasure of SCE's Board of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. All of the executive officers have been actively engaged in the business of SCE for more than five years except for Stephen E. Frank. Those officers who have not held their present position for the past five years had the following business experience.

Executive Officer	Company Position	Effective Dates
Stephen E. Frank	Chairman of the Board, President, Chief Executive Officer and Director President, Chief Operating Officer and Director President and Chief Operating Officer, Florida Power and Light Company[(1)]	January 2000 to present June 1995 to December 1999 August 1990 to January 1995
Harold B. Ray	Executive Vice President, Generation Business Unit Senior Vice President, Power Systems	June 1995 to present June 1990 to May 1995
Pamela A. Bass	Senior Vice President, Customer Service Business Unit Vice President, Customer Solutions Business Unit Vice President, Shared Services Division Vice President, ENvest	March 1999 to present June 1996 to February 1999 January 1996 to May 1996 August 1993 to December 1995
John R. Fielder	Senior Vice President, Regulatory Policy and Affairs Vice President, Regulatory Policy and Affairs	February 1998 to present February 1992 to February 1998
Robert G. Foster	Senior Vice President, Public Affairs Vice President, Public Affairs	November 1996 to present November 1993 to October 1996
Richard M. Rosenblum	Senior Vice President, T&D Business Unit Vice President, Distribution Business Unit Vice President, Nuclear Engineering and Technical Services	February 1998 to present January 1996 to February 1998 June 1993 to December 1995
Thomas M. Noonan	Vice President and Controller Assistant Controller	March 1999 to present September 1993 to February 1999
Stephen E. Pickett	Vice President and General Counsel Associate General Counsel	January 2000 to present November 1993 to December 1999
Anthony L. Smith	Vice President, Tax Assistant Controller	March 1999 to present January 1998 to February 1999

(1) This entity is not a parent, subsidiary or other affiliate of SCE.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

Certain information responding to Item 5 with respect to frequency and amount of cash dividends is included in SCE's Annual Report to Shareholders for the year ended December 31, 1999, (Annual Report) under "Quarterly Financial Data" on page 33 and is incorporated by reference pursuant to General Instruction G(2). As a result of the formation of a holding company described above in Item 1, all of the issued and outstanding common stock of SCE is owned by Edison International and there is no market for such stock.

Item 6. Selected Financial Data

Information responding to Item 6 is included in the Annual Report under "Selected Financial and Operating Data: 1995-1999" on page 36 and is incorporated herein by reference pursuant to General Instruction G(2).

Item 7. Management's Discussion and Analysis of Results of Operations and Financial Condition

Information responding to Item 7 is included in the Annual Report under "Management's Discussion and Analysis of Results of Operations and Financial Condition" on pages 1 through 10 and is incorporated herein by reference pursuant to General Instruction G(2).

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A is included in the Annual Report under "Management's Discussion and Analysis of Results of Operations and Financial Condition" on page 4 through 5 incorporated herein by reference pursuant to General Instruction G(2), and in Part I, Item 1 of this report on pages 6 through 7 under "Market Risk Exposures".

Item 8. Financial Statements and Supplementary Data

Certain information responding to Item 8 is set forth after Item 14 in Part IV. Other information responding to Item 8 is included in the Annual Report on pages 11 through 33, and is incorporated herein by reference pursuant to General Instruction G(2).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information concerning executive officers of SCE is set forth in Part I in accordance with General Instruction G(3), pursuant to Instruction 3 to Item 401(b) of Regulation S-K. Other information responding to Item 10 is included in the Joint Proxy Statement (Proxy Statement) filed with the SEC in connection with SCE's Annual Meeting to be held on April 20, 2000, under the heading, "Election of Directors" on pages 6 and 7 and "Section 16(a) Beneficial Ownership Reporting Compliance" on page 13, and is incorporated herein by reference pursuant to General Instruction G(3).

Item 11. Executive Compensation

Information responding to Item 11 is included in the Proxy Statement beginning with the section under the heading "Executive Compensation Summary Compensation Table" beginning on page 15 and continuing through page 25, excluding the "Compensation and Executive Personnel Committees' Report on Executive Compensation," and is incorporated herein by reference pursuant to General Instruction G(3).

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information responding to Item 12 is included in the Proxy Statement under the headings "Stock Ownership of Directors and Executive Officers" on pages 12 and 13 and "Stock Ownership of Certain Shareholders" on page 14, and is incorporated herein by reference pursuant to General Instruction G(3).

Item 13. Certain Relationships and Related Transactions

Information responding to Item 13 is included in the Proxy Statement under the heading "Certain Relationships and Transactions of Nominees and Executive Officers" on page 30 and is incorporated herein by reference pursuant to General Instruction G(3).

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) (1) Financial Statements

The following items contained in the Annual Report are found on pages 1 through 35, and incorporated by reference in this report.

Management's Discussion and Analysis of Results of Operations and Financial Condition
Consolidated Statements of Income -- Years Ended December 31, 1999, 1998 and 1997
Consolidated Statements of Comprehensive Income -- Years Ended December 31, 1999, 1998 and 1997
Consolidated Balance Sheets -- December 31, 1999, and 1998
Consolidated Statements of Cash Flows -- Years Ended December 31, 1999, 1998 and 1997
Consolidated Statements of Changes in Common Shareholder's Equity -- Years Ended December 31, 1999, 1998 and 1997
Notes to Consolidated Financial Statements
Responsibility for Financial Reporting
Report of Independent Public Accountants

(2) Report of Independent Public Accountants and Schedules Supplementing Financial Statements

The following documents may be found in this report at the indicated page numbers.

Schedules I through V, inclusive, except those referred to above, are omitted as not required or not applicable.

(3) Exhibits

See Exhibit Index on page 33 of this report.

(b) Reports on Form 8-K

October 6, 1999	
Item 5: Other Events	Mohave Generating Station Environmental Litigation

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SUPPLEMENTAL SCHEDULES

To Southern California Edison Company:

We have audited, in accordance with auditing standards generally accepted in the United States, the consolidated financial statements included in the 1999 Annual Report to Shareholders of Southern California Edison Company (SCE) incorporated by reference in this Form 10-K, and have issued our report thereon dated February 2, 2000. Our audits of the consolidated financial statements were made for the purpose of forming an opinion on those basic consolidated financial statements taken as a whole. The supplemental schedules listed in Part IV of this Form 10-K, which are the responsibility of SCE's management, are presented for purposes of complying with the Securities and Exchange Commission's rules and regulations, and are not part of the basic consolidated financial statements. These supplemental schedules have been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Los Angeles, California
February 2, 2000

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1999

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
Group A:					
Uncollectible accounts--					
Customers	$ 19,596	$ 21,968	--	$ 19,908	$ 21,656
All other	2,634	1,288	--	913	3,009
Total	$ 22,230	$ 23,256	--	$ 20,821 (a)	$ 24,665
Group B:					
DOE Decontamination and Decommissioning	$ 39,419	--	$ (134) (b)	$ 4,695 (c)	$ 34,590
Purchased-power settlements	129,697	$466,043	--	32,281 (d)	563,459
Pension and benefits	239,668	48,894	21,674 (e)	77,335 (f)	232,901
Insurance, casualty and other	73,249	37,674	--	42,043 (g)	68,880
Total	$482,033	$552,611	$ 21,540	$156,354	$899,830

(a) Accounts written off, net.

(b) Represents revision to estimate based on actual billings.

(c) Represents amounts paid.

(d) Represents the amortization of the liability established for purchased-power contract settlement agreements.

(e) Primarily represents transfers from the accrued paid absence allowance account for required additions to the comprehensive disability plan accounts.

(f) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.

(g) Amounts charged to operations that were not covered by insurance.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1998

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
Group A:					
Uncollectible accounts--					
Customers	$ 24,245	$ 19,808	--	$ 24,457	$ 19,596
All other	2,208	2,273	--	1,847	2,634
Total	$ 26,453	$ 22,081	--	$ 26,304 (a)	$ 22,230
Group B:					
DOE Decontamination and Decommissioning	$ 44,336	--	$ (89) (b)	$ 4,828 (c)	$ 39,419
Purchased-power settlements	145,640	--	--	15,943 (d)	129,697
Pension and benefits	211,200	$170,743	18,988 (e)	161,263 (f)	239,668
Insurance, casualty and other	78,461	69,275	--	74,487 (g)	73,249
Total	$479,637	$240,018	$ 18,899	$256,521	$482,033

(a) Accounts written off, net.

(b) Represents revision to estimate based on actual billings.

(c) Represents amounts paid.

(d) Represents the amortization of the liability established for purchased-power contract settlement agreements.

(e) Primarily represents transfers from the accrued paid absence allowance account for required additions to the comprehensive disability plan accounts.

(f) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.

(g) Amounts charged to operations that were not covered by insurance.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1997

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (In thousands)	Deductions	Balance at End of Period
Group A:					
Uncollectible accounts-- Customers	$ 24,390	$ 20,597	--	$ 20,742	$ 24,245
All other	1,689	1,180	--	661	2,208
Total	$ 26,079	$ 21,777	--	$ 21,403(a)	$ 26,453
Group B:					
DOE Decontamination and Decommissioning	$ 48,789	--	$ 1,089(b)	$ 5,542(c)	$ 44,336
Purchased-power settlements	107,700	--	67,320(d)	29,380(e)	145,640
Pension and benefits	180,927	$102,193	17,624(f)	89,544(g)	211,200
Insurance, casualty and other	86,509	57,749	--	65,797(h)	78,461
Total	$423,925	$159,942	$ 86,033	$190,263	$479,637

(a) Accounts written off, net.

(b) Represents revision to estimate based on actual billings.

(c) Represents amounts paid.

(d) Represents additional payments to be made under agreements to terminate purchased-power contract.

(e) Represents the amortization of the liability established for purchased-power contract settlement agreements.

(f) Primarily represents transfers from the accrued paid absence allowance account for required additions to the comprehensive disability plan accounts.

(g) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.

(h) Amounts charged to operations that were not covered by insurance.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHERN CALIFORNIA EDISON COMPANY

By Kenneth S. Stewart

Kenneth S. Stewart
Assistant General Counsel

Date: March 28, 2000

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
Principal Executive Officer:		
Stephen E. Frank*	Chairman of the Board, President, Chief Executive Officer and Director	March 28, 2000
Principal Financial Officer:		
W. James Scilacci*	Vice President and Chief Financial Officer	March 28, 2000
Controller or Principal Accounting Officer:		
Thomas M. Noonan*	Vice President and Controller	March 28, 2000
Board of Directors:		
Winston H. Chen*	Director	March 28, 2000
Warren Christopher*	Director	March 28, 2000
Stephen E. Frank*	Director	March 28, 2000
Joan C. Hanley*	Director	March 28, 2000
Carl F. Huntsinger*	Director	March 28, 2000
Charles D. Miller*	Director	March 28, 2000
Luis G. Nogales*	Director	March 28, 2000
Ronald L. Olson*	Director	March 28, 2000
James M. Rosser*	Director	March 28, 2000
Robert H. Smith*	Director	March 28, 2000
Thomas C. Sutton*	Director	March 28, 2000
Daniel M. Tellep*	Director	March 28, 2000
Edward Zapanta*	Director	March 28, 2000

*By: Kenneth S. Stewart

Kenneth S. Stewart
Assistant General Counsel

EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Amendment and Restated Articles of Incorporation of SCE effective June 1, 1993 (File No. 1-2313, Form 10-K for the year ended December 31, 1993)*
3.2	Certificate of Correction of Restated Articles of Incorporation of SCE dated June 23, 1997 (File No. 1-2313, Form 10-Q for the quarter ended September 30, 1997)*
3.3	Amended Bylaws of Southern California Edison Company as adopted by the Board of Directors on February 17, 2000
4.1	SCE First Mortgage Bond Trust Indenture, dated as of October 1, 1923 (Registration No. 2-1369)*
4.2	Supplemental Indenture, dated as of March 1, 1927 (Registration No. 2-1369)*
4.3	Third Supplemental Indenture, dated as of June 24, 1935 (Registration No. 2-1602)*
4.4	Fourth Supplemental Indenture, dated as of September 1, 1935 (Registration No. 2-4522)*
4.5	Fifth Supplemental Indenture, dated as of August 15, 1939 (Registration No. 2-4522)*
4.6	Sixth Supplemental Indenture, dated as of September 1, 1940 (Registration No. 2-4522)*
4.7	Eighth Supplemental Indenture, dated as of August 15, 1948 (Registration No. 2-7610)*
4.8	Twenty-Fourth Supplemental Indenture, dated as of February 15, 1964 (Registration No. 2-22056)*
4.9	Eighty-Eighth Supplemental Indenture, dated as of July 15 1992 (File No. 1-2313, Form 8-K dated July 22, 1992)*
4.10	Indenture dated as of January 15, 1993 (File No. 1-2313, Form 8-K dated January 28, 1993)*
10.1	1981 Deferred Compensation Agreement (File No. 1-2313, filed as Exhibit 10.2 to Form 10-K for the year ended December 31, 1981)*
10.2	1985 Deferred Compensation Agreement for Executives (File No. 1-2313, filed as Exhibit 10.3 to Form 10-K for the year ended December 31, 1986)*
10.3	1985 Deferred Compensation Agreement for Directors (File No. 1-2313, filed as Exhibit 10.4 to Form 10-K for the year ended December 31, 1986)*
10.4	Director Deferred Compensation Plan (File No. 1-2313, filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 1998)*
10.5	Director Grantor Trust Agreement (File No. 1-2313, filed as Exhibit 10.10 to Form 10-K for the year ended December 31, 1995)*
10.6	Executive Deferred Compensation Plan (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 1998)*
10.7	Executive Grantor Trust Agreement (File No. 1-2313, filed as Exhibit 10.12 to Form 10-K for the year ended December 31, 1995)*
10.8	Executive Supplemental Benefit Program as amended effective January 30, 1990 (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 1999)*
10.9	Executive Retirement Plan as amended effective April 1, 1999 (File No. 1-2313, filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 1999)*
10.10	Executive Incentive Compensation Plan (File No. 1-2313, filed as Exhibit 10.12 to Form 10-K for the year ended December 31, 1997)*

Exhibit Number	Description
10.11	Executive Disability and Survivor Benefit Program (File No. 1-2313, filed as Exhibit 10.22 to Form 10-K for the year ended December 31, 1994)*
10.12	Retirement Plan for Directors (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 1998)*
10.13	Officer Long-Term Incentive Compensation Plan as amended effective January 1, 1998 (File No. 1-2313, filed as Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 1998)*
10.13.1	Form of Agreement for 1989-1995 Awards under the Officer Long-Term Incentive Compensation Plan (File No. 1-2313, filed as Exhibit 10.21.1 to Form 10-K for the year ended December 31, 1995)*
10.13.2	Form of Agreement for 1996 Awards under the Officer Long-Term Incentive Compensation Plan (File No. 1-2313, filed as Exhibit 10.16.2 to Form 10-K for the year ended December 31, 1996)*
10.13.3	Form of Agreement for 1997 Awards under the Officer and Management Long-Term Incentive Compensation Plans (File No. 1-2313, filed as Exhibit 10.16.3 to Form 10-K for the year ended December 31, 1997)*
10.14	Equity Compensation Plan (File No. 1-2313, filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 1998)*
10.14.1	Form of Agreement for 1998 Employee Awards under the Equity Compensation Plan (File No. 1-2313, filed as Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 1998)*
10.14.2	Form of Agreement for 1998 Director Awards under the Equity Compensation Plan (File No. 1-2313, filed as Exhibit 10.5 to Form 10-Q for the quarter ended June 30, 1998)*
10.14.3	Form of Agreement for 1999 Employee Awards (File No. 1-2313, filed as Exhibit 10 to Form 10-Q for the quarter ended March 31, 1999)*
10.14.4	Form of Agreement for 1999 Director Awards under the Equity Compensation Plan (File No. 1-2313, filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 1999)*
10.15	Estate and Financial Planning Program as amended April 1, 1999 (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 1999)*
10.16	Option Gain Deferral Plan (File No. 1-2313, filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 1998)*
10.17	Employment Letter Agreement with Bryant C. Danner (File No. 1-2313, filed as Exhibit 10.27 to Form 10-K for the year ended December 31, 1992)*
10.18	Employment Letter Agreement with Stephen E. Frank (File No. 1-2313, filed as Exhibit 10.25 to Form 10-K for the year ended December 31, 1995)*
10.19	Election Terms for Warren Christopher (File No. 1-2313, filed as Exhibit 10.21 to Form 10-K for the year ended December 31, 1997)*
10.20	Dispute resolution amendment of 1981 Executive Deferred Compensation Plan, 1985 Executive and Director Deferred Compensation Plans and Executive Supplemental Benefit Program (File No. 1-2313, filed as Exhibit 10.20 to Form 10-K for the year ended December 31, 1998)*
12.	Computation of Ratios of Earnings to Fixed Charges
13.	Annual Report to Shareholders for year ended December 31, 1999
23.	Consent of Independent Public Accountants - Arthur Andersen LLP
24.1	Power of Attorney
24.2	Certified copy of Resolution of Board of Directors Authorizing Signature
27.	Financial Data Schedule

* Incorporated by reference pursuant to Rule 12b-32.

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