JUN 17 1997

June 13, 1997

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

Gentlemen:

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

Southern California Edison (Edison), as agent for the owners of San Onofre Nuclear Generating Stations Units 2 and 3 and Edison'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):

- 1997 Internal Cash Flow Projection which is derived from Consolidated Financial Statements included in Edison's 1996 Annual Report to Shareholders, as audited and certified by Arthur Anderson, LLP.
- Edison's Annual Report to Shareholders for the fiscal year ending December 31, 1996.
- Edison's Form 10K Annual Report to the Securities and Exchange Commission (Form 10K) for the fiscal year ending December 31, 1996

If you have any questions or require further information about these documents, please contact me.

Sincerely,

J. L. Rainsberry
Manager, Plant Licensing

Enclosure
C:\NETWP6\TWR\97ICFPV.TW2

cc: E. W. Merschoff, Regional Administrator, NRC Region IV
K. E. Perkins, Jr., Director, Walnut Creek Field Office, NRC Region IV
J. A. Sloan, NRC Senior Resident Inspector, San Onofre Units 2 & 3
M. B. Fields, NRC Project Manager, San Onofre Units 2 and 3
C. R. Thomas, NRC Project Manager, Palo Verde Unit 3

bcc: (See attached sheet)

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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, 1996

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)	(818) 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		$100 Cumultive Preferred	American and Pacific
4.08% Series	4.78% Series	6.05% Series	
4.24% Series	5.80% Series	6.45% Series	
4.32% Series	7.36% Series	7.23% Series	

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 21, 1997, there were 419,726,654 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 $518,107,275 on or about March 21, 1997, based upon prices reported by the American Stock Exchange. The market values of the various classes of voting stock held by non-affiliates were as follows: CUMULATIVE PREFERRED STOCK $229,444,775; $100 CUMULATIVE PREFERRED STOCK $288,662,500. The market values for the $100 Cumulative Preferred Stock, which are unlisted, were obtained from broker quotes.

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, 1996	Parts I, II and IV
(2)	Designated portions of the Joint Proxy Statement relating to registrant's 1997 Annual Meeting of Shareholders	Part III

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PART I

Item 1. Business

Southern California Edison Company ("SCE") was incorporated under California law in 1909. 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. This area includes some 800 cities and communities and a population of more than 11 million people. SCE had 12,057 full-time employees during 1996. During 1996, 39% of SCE's total operating revenue was derived from residential customers, 37% from commercial customers, 12% from industrial customers, 7% from public authorities, 4% from agricultural and other customers and 1% from resale customers. SCE comprises the major portion of the assets and revenue of Edison International, its parent holding company.

Competitive Environment

SCE currently operates in a highly regulated environment in which it has an obligation to provide electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing. The generation sector has experienced competition from nonutility power producers and regulators are restructuring California's electric utility industry.

On September 23, 1996, the State of California enacted legislation to provide a transition to a competitive market structure. The legislation substantially adopts the CPUC's December 1995 restructuring decision (discussed below) by addressing stranded-cost recovery for utilities, providing a certain cost recovery time period for the transition costs associated with utility-owned generation-related assets. Transition costs related to power-purchase contracts would be recovered through the terms of their contracts while most of the remaining transition costs would be recovered through 2001. The legislation also includes provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, thereby allowing SCE to give a rate reduction of at least 10% to these customers, beginning January 1, 1998. The financing would occur with securities issued by the California Infrastructure and Economic Development Bank, or an entity approved by the Bank. The legislation includes a rate freeze for all other customers, including large commercial and industrial customers, as well as provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement based on cost-of-service regulation during the 1998-2001 transition period. In addition, the legislation mandates the implementation of a non-bypassable competition transition charge (CTC) that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the legislation contains provisions for the recovery (through 2006) of reasonable employee-related transition costs incurred and projected for retraining, severance, early retirement, outplacement and related expenses for utility workers. In light of the legislation, the CPUC has indicated that it need not prepare an environmental impact report in connection with its December 1995 restructuring policy decision.

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

- Creation of an independent power exchange (PX) to manage electric supply and demand. California's investor-owned utilities would be

required to purchase from and sell to the PX all of their power during the transition period, while other generators could voluntarily participate.

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

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

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

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

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

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

Recovery of costs to transition to a competitive market would be implemented through a non-bypassable CTC. This charge would apply to all customers who were using or began using utility services on or after the December 20, 1995, decision date. In August 1996, in compliance with the CPUC's restructuring decision, SCE filed its application to estimate its 1998 transition costs. In October 1996, SCE amended its transition cost filing to reflect the effects of the legislation enacted in September 1996. Under the rate freeze codified in the legislation, the CTC will be determined residually (i.e., after subtracting other cost components for the PX, transmission and distribution (T&D), nuclear decommissioning and public benefit programs). Nevertheless, the CPUC directed that the amended application provide estimates of SCE's potential transition costs from 1998 through 2030. SCE provided two estimates between approximately $13.1 billion (1998 net present value), assuming the fossil plants have a market value equal to their net book value, and $13.8 billion (1998 net present value), assuming the fossil plants have no market value. These estimates are based on incurred costs, and forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. The potential transition cost estimates are comprised of: $7.5 billion from SCE's qualifying facility contracts, which are the direct result of legislative and regulatory mandates; and $5.6 billion to $6.3 billion from costs pertaining to certain generating plants and regulatory commitments

consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed-through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre and Palo Verde and certain other costs. An update to the CTC was filed by SCE on February 14, 1997, to reflect approval by the CPUC of settlements regarding ratemaking of SCE's share of the Palo Verde Nuclear Generating Station and the buyout of a power purchase agreement with Portland General Electric, as well as other minor data updates. No substantive changes in the total CTC estimates were included.

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

In September 1996, the CPUC adopted a non-generation T&D PBR mechanism for SCE which began on January 1, 1997. According to the CPUC decision, beginning in 1998, the transmission portion controlled by the ISO is to be separated from non-generation PBR and subject to ratemaking under the rules of the FERC. The distribution-only PBR will extend through December 2001. Key elements of the non-generation PBR include: T&D rates indexed for inflation based on the Consumer Price Index less a productivity factor; elimination of the kilowatt-hour sales adjustment; adjustments for cost changes that are not within SCE's control; a cost of capital trigger mechanism based on changes in a bond index; standards for service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from T&D operations. In July 1996; SCE filed a PBR proposal for its hydroelectric plants and a proposed structure for performance-based local reliability contracts for certain fossil-fueled plants. If approved, the hydro PBR would be in effect for three years and the initial terms of the local reliability contracts, which are subject to FERC approval, would be in effect for up to three years, both beginning January 1, 1998. A final CPUC decision on hydro PBR is expected by year-end 1997.

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

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

studies that reflect the physical useful lives of the assets. SCE also believes that any depreciation-related differences would be recovered through the CTC.

If events occur during the restructuring process that result in all or a portion of the CTC being improbable of recovery, SCE could have write-offs associated with these costs if they are not recovered through another regulatory mechanism. At this time, SCE cannot predict what other revisions will ultimately be made during the restructuring process in subsequent proceedings or implementation phases, or the effect, after the transition period, that competition will have on its results of operations or financial position.

Subsequent Event

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

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

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

Unbundling of Distribution Services

On October 25, 1996, the CPUC issued an Order directing SCE to submit comments on, and cost estimates for, providing metering, billing, and related customer services. The CPUC issued the Order in connection with its ongoing investigation of the policies governing the restructuring of

California's electric services industry. The purpose of this aspect of the CPUC's investigation is to determine the extent to which, if at all, nonutility energy service providers should be allowed to offer metering, billing, and related customer services, which currently are provided exclusively by SCE as part of its franchise service obligation. Such "unbundling" would expose SCE to potential financial losses in these services, potential stranded costs and create the potential for reduced revenue security. SCE submitted comments in compliance with the CPUC's Order on December 20, 1996. SCE submitted further comments on January 21, 1997 and February 7, 1997. The CPUC held a full-panel hearing on these matters on January 15, 1997, following which the Administrative Law Judge issued a proposed decision recommending that the CPUC "unbundle" metering and billing services in early 1998. SCE filed opening comments on the proposed Decision on March 6, 1997; on March 11, SCE submitted reply comments. The CPUC is expected to issue a decision setting forth its proposed policies in the second quarter of 1997. The CPUC is not bound by the proposed decision: they may accept it in whole or part, or may reject it and consider the matter further. Due to the uncertainty surrounding any future policies the CPUC may adopt with respect to unbundling, SCE is unable to provide an estimate of the potential financial impact of such policies.

Automated Meter Reading Proposal

SCE is developing a pilot automated meter reading (AMR) network capable of reading 20-50,000 meters at the cost of $12 million. The installation is underway and should be completed in 1997. If successful, SCE expects to proceed with full-scale deployment to 85 percent (3.6 million) of its customers. The full project would start in late 1997 and take four years to complete at an estimated capital cost of $350 million. The AMR system would allow SCE to read meters from a remote location and enable customers to respond to hourly price signals envisioned by electric restructuring beginning in January 1, 1998. Some of these costs would be offset by savings in operations and maintenance expenses, due to the reduction of manual meter reading. The net cost is expected to be approximately $75 million. On December 20, 1996, as part of its comments on unbundling (see above), SCE presented its AMR proposal to the CPUC. In the comments, SCE proposed the net cost of the project would be included in rates after the rate freeze required by Assembly Bill 1890 in 2002. As previously noted, SCE is expecting a CPUC decision concerning the unbundling of revenue cycle services and its AMR proposal in the second quarter of 1997.

Regulation

SCE's retail operations are subject to regulation by the CPUC. The CPUC has the authority to regulate, among other things, retail rates, issuances of securities and accounting practices. SCE's wholesale operations are subject to regulation by the 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 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 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

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 Units 2 and 3. Although the units are operating, the permit's mitigation requirements have not yet been fulfilled. 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, solar energy development, power plant fuel use and disposal, coal conversion, electric sales for export, public utility regulatory policy and natural gas pricing.

Rate Matters

CPUC Retail Ratemaking

The rates for electricity provided by SCE to its retail customers comprise several major components established by the CPUC to compensate SCE for basic business and operational costs, fuel and purchased-power costs, and the costs of adding major new facilities.

Basic business and operational costs are recovered through base rates, which are determined in general rate case proceedings held before the CPUC every three years. CPUC decisions on SCE's PBR proposals (discussed under Competitive Environment) and the ongoing electric industry restructuring (discussed above) could affect the need for future general rate case proceedings. During a general rate case, the CPUC critically reviews SCE's operations and general costs to provide service (excluding energy costs and, in certain instances, major plant additions). The CPUC then determines the revenue requirement to cover those costs, including items such as depreciation, taxes, operation, maintenance, and administrative and general expenses. The revenue requirement is forecasted on the basis of a specified test year. Following the revenue requirement phase of a general rate case, SCE and the CPUC proceed to a rate design phase which allocates revenue requirements and establishes rate levels for customers.

SCE's fuel, purchased-power and energy-related costs of providing electric service are recovered through a balancing account mechanism called the Energy Cost Adjustment Clause ("ECAC"). Under the ECAC balancing account procedure, actual fuel, purchased-power and energy-related revenue and costs are compared and the difference is recorded as either an undercollection or overcollection. The amount recorded in the balancing account is periodically amortized through rate changes which return overcollections to customers by reducing rates or collect undercollections from customers by increasing rates. The costs recorded in the ECAC balancing account are subject to reasonableness reviews by the CPUC. The reasonableness of execution and the ongoing administration of all purchased-power contracts including contracts with QFs is also reviewed in ECAC proceedings by the CPUC. During recent ECAC periods, in excess of $2.5 billion in costs arising from such contracts has annually been submitted for CPUC review. The CPUC has not yet completed its review of all of SCE's energy and fuel related costs for the period April 1, 1990, to the present. Certain incentive provisions are included in the ECAC that can affect the amount of fuel and energy-related costs actually recovered. SCE is required to make an ECAC filing for each calendar year, and must also make a second filing for a mid-year adjustment if it would result in an ECAC rate change exceeding 5% of total annual revenue.

The CPUC has also adopted a Nuclear Unit Incentive Procedure ("NUIP") which provides for a sharing of additional energy costs or savings between SCE and its ratepayers when operation of any of the units of San Onofre or Palo Verde Units is outside a specified range (55% to 80% of each unit's capacity factor). The NUIP ended for San Onofre Units 2 and 3 at the end of fuel cycle number seven which occurred on May 23, 1995, and September 26, 1995, respectively. The CPUC also modified the NUIP for Palo Verde Units 1, 2 and 3. The NUIP for Palo Verde will continue through December 31, 2001, for purposes of calculating a reward only. The current NUIP period, which would have included the average of Fuel Cycles 6 and 7, was adjusted for Palo Verde to include only Fuel Cycle 6. If any of the three Palo Verde units operate above an 80% Gross Capacity Factor (GCF) for a subsequent fuel cycle within the period, the NUIP reward will be calculated based on the difference between the additional variable cost and the market price (or replacement power cost until the market becomes operational) for the output above an 80% GCF. Any NUIP reward based upon a fuel cycle not completed by December 31, 2001 will be calculated on a pro-rata basis ending November 1, 2001.

The Electric Revenue Adjustment Mechanism reflects the difference between the recorded and authorized level of base rate revenue. The CPUC adopted this mechanism primarily to minimize the effect on earnings of fluctuations in retail kilowatt-hour sales.

Energy Cost Adjustment Clause ("ECAC")

A CPUC decision related to SCE's 1996 authorized revenue for fuel and purchased power was issued on February 23, 1996. At issue was the treatment of a $237 million overcollection in ECAC. The CPUC ordered a one-time credit applied to customer bills in 1996. SCE's 1996 CPUC-authorized revenue, including the effects of other rate actions, was reduced by $338 million or 4.4%. SCE was required to credit customer bills in June 1996 and did refund the $237 million overcollection referred to above.

1992 Annual ECAC Application

SCE filed its testimony in the QF reasonableness phase of SCE's 1992 ECAC proceeding on September 1, 1992. On January 16, 1996, the CPUC's Office of Ratepayer Advocates ("ORA") released its report on QF reasonableness for both the 1992 record period and as to issues that had been reserved from the 1991 ECAC proceeding. The report recommends: (1) disallowances of $8,678,458 for the 1992 record period and $8,039,177 for the 1991 record period attributable to alleged deficiencies in how SCE administers the firm capacity payment provisions in its agreements with QFs; (2) disallowances of $5,904,143 for the 1992 record period and $5,007,701 for the 1991 record period regarding QF sales of energy that exceed the nameplate ratings specified by the QF in Interim Standard Offer No. 4 (ISO4) contracts and negotiated contracts containing similar payment provisions; and (3) disallowances of $21,150 for the 1992 record period and $21,751 for the 1991 record period relating to purchases of as-available capacity from QFs in excess of the nameplate ratings specified by the QF in ISO4 and similar contracts. The report requests that such disallowances be assessed on a continuing basis until SCE ends its challenged practices in these areas. No schedule has been set for further testimony or hearings on these issues.

1994 Annual ECAC Application

In May 1994, SCE filed its testimony in the non-Qualifying Facilities phase of the 1994 Energy Cost Adjustment Clause proceeding. In May 1995, the ORA filed its report on the reasonableness of SCE's gas supply costs for both the 1993 and 1994 record periods. The report recommends a disallowance of $13.3 million for excessive costs incurred from November 1993 through March 1994 associated with SCE's Canadian gas purchase and supply contracts. The report requests that the CPUC defer finding SCE's

Canadian supply and transportation agreements reasonable for the duration of their terms and that the costs under these contracts be reviewed on a yearly basis. In October 1996, the ALJ consolidated the hearings for gas reasonableness issues in A. 95-05-049 covering the period April 1, 1994 through March 31, 1995 with the 1994 Application. ORA has recommended a disallowance of $37.5 million for excessive costs for the 1995 record period. If formation of these contracts is not found reasonable by the CPUC, any costs found unreasonable would be disallowed in subsequent record periods. An adverse ruling by the CPUC on contract reasonableness could also affect SCE's future recovery of any termination costs associated with these contracts. SCE and ORA have filed several rounds of testimony on this issue. Hearings began in January 1997 and concluded in February 1997. A decision is expected in late 1997.

1995 Annual ECAC Application

SCE filed its Reasonableness of Operations testimony on May 26, 1996. The non-QF report addresses power purchases and exchanges, and the operation of hydro, coal, gas and nuclear resources for the period April 1, 1994, through March 31, 1995. In May 1996, the ORA issued its reasonableness report on several reasonableness issues. The Report recommends a $6,623,936 disallowance for replacement fuel expenses associated with 64 outage days due to the Palo Verde Nuclear Generating Station Unit 2 steam generator tube rupture in 1993. In February 1997, SCE filed its rebuttal testimony addressing these issues. No schedule has been set for the reasonableness phase.

On October 4, 1996, the ORA issued its report on SCE's Canadian gas procurement contracts discussed above. The report recommends a $37.6 million disallowance for the period April 1994 through March 1995. On October 17, 1996, the ALJ consolidated the gas reasonableness issues into the 1994 ECAC proceeding. SCE filed rebuttal testimony on December 31, 1996. Hearings on this matter began in January 1997 and concluded in February 1997. A decision is expected in late 1997.

Mohave Generating Station

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

<u>FERC Stranded Cost/Open Access Transmission Decision</u>

In April 1996, the FERC issued its decision on stranded cost recovery and open access transmission effective July 1996. The FERC issued an order reaffirming its basic determinations, clarifying certain terms, and making several changes in March 1997. The decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with increased access to transmission facilities for wholesale transactions and also establishes information requirements for the transmission utility. The April 1996 decision, affirmed in the March 1997 decision, also provides utilities with the recovery of stranded costs, which are prior-service costs incurred under the current regulatory framework. In addition to providing recovery of stranded costs associated with existing wholesale customers, the FERC directed that it would have primary jurisdiction over the recovery of stranded costs associated with retail-turned-wholesale customers (e.g., a new municipal electric system), although the FERC did clarify that it does not intend to prevent or interfere with the authority of a state and that it has discretion to defer to a state stranded cost calculation method. Also in the March 1997 decision, the FERC expanded its authority on stranded cost recovery associated with retail-turned-wholesale customers to include municipal annexations. Retail stranded costs resulting from a state-authorized

retail direct-access program are the responsibility of the states and the FERC would only address recovery of these costs if the state has no authority to do so. However, the FERC clarified that it will not entertain such requests if a state regulatory authority has addressed such costs, regardless of whether the state regulatory authority has allowed full recovery, partial recovery, or no recovery. In compliance with the April 1996 FERC decision, SCE filed a revised open access tariff with the FERC in July 1996. The tariff became effective, on an interim basis, subject to refund, as of its filing date. The FERC accepted SCE's compliance filing in February 1997. SCE will revise its tariff to reflect the few revisions set forth in the March 1997 order.

Palo Verde Ratemaking Proposal

On December 20, 1996, the CPUC issued a final decision on SCE's proposal for a new rate mechanism for its 15.8% share of the three units at Palo Verde. The decision adopts the Palo Verde All-Party Settlement filed with the CPUC on November 15, 1996. The settlement was based on a Memorandum of Understanding signed by all of the active parties to the Palo Verde proceeding. Under the settlement, SCE has the opportunity to recover its remaining investment (approximately $1.2 billion) in Palo Verde beginning January 1, 1997, and ending December 31, 2001, earning a reduced rate of return on rate base of 7.35% instead of the current 9.49%. Also, SCE will utilize a balancing account to pass through Palo Verde's incremental operating costs (considered reasonable so long as they do not exceed 30% of a baseline forecast and the site's gross annual capacity factor does not go below 55%) to ratepayers. Beginning January 1, 1998, this balancing account will become part of the CTC mechanism. If SCE's actual costs are less than the forecast, the difference will benefit ratepayers as a credit to the CTC mechanism. After 2001, SCE's ratepayers will receive 50% of the benefits derived from the operation of Palo Verde.

Workforce Reductions

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

Proposed New Accounting Standard

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

Fuel Supply and Purchased Power Costs

Fuel and purchased-power costs were approximately $3.3 billion in 1996, a 4.4% increase over 1995.

SCE's sources of energy during 1996 were: purchased power 45%; natural gas 15%; nuclear 21%; coal 12%; and hydro 7%.

Average fuel costs, expressed in cents per kilowatt-hour, for the year ended December 31, 1996, were: oil, 7.67 cents; natural gas, 2.94 cents; nuclear, 0.48 cents; and coal, 1.37 cents.

Natural Gas Supply

Twelve of SCE's major steam electric generating plants are designed to burn oil or natural gas as the primary boiler fuel. In 1990, SCE adopted an all-gas strategy to comply with air quality goals by eliminating burning oil in all but very extreme conditions. In August 1991, the CPUC adopted regulations which made SCE fully responsible for all natural gas procurement activities previously performed by local distribution companies.

To implement its all-gas strategy, SCE acquired a balanced portfolio of gas supply and transportation arrangements. Traditionally, natural gas needs in southern California were met from gas production in the southwest region of the country. To diversify its gas supply, SCE entered into four 15-year natural gas supply agreements with major producers in western Canada. These contracts, totaling 200,000,000 cubic feet per day, have market-sensitive pricing arrangements. This represents about 55% of SCE's current average annual supply needs. The rest of SCE's gas supply is acquired under short-term contracts from Texas, New Mexico and the Rocky Mountain region.

Firm transportation arrangements provide the necessary long-term reliability for supply deliverability. To transport Canadian supplies, SCE contracted for 200,000,000 cubic feet per day of firm transportation arrangements on the Pacific Gas Transmission and Pacific Gas & Electric Expansion Project connecting southern California to the low-cost gas producing regions of western Canada. SCE has a 30-year commitment to this project, construction of which was completed in late 1993. In addition, SCE has a 15-year commitment with El Paso Natural Gas to transport 200,000,000 cubic feet per day (option to step down to 130,000,000 cubic feet per day in 1997) from the southwestern U.S.

Nuclear Fuel Supply

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

	Units 2 & 3
Uranium concentrates(1)	2003
Conversion	2003
Enrichment	2003
Fabrication	2005
Spent fuel storage(2)	2006/2006

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

(2) Assumes full utilization of expanded on-site storage capacity and normal operation of the units, including interpool transfers and maintaining full-core reserve. To supplement existing spent fuel storage, a contingency plan is being developed to construct additional on-site storage capacity with initial operation scheduled for no later than 2005. The Nuclear Waste Policy Act of 1982 requires that the DOE provide for the disposal of utility spent nuclear fuel beginning in 1998. The DOE has stated that it will not be able to meet the 1998 date to start accepting spent nuclear fuel and has requested stakeholder input as to the best course of action to accommodate the delay.

Participants in Palo Verde have purchased uranium concentrates sufficient to meet projected requirements through 1997. Independent of arrangements made by other participants, SCE will furnish its share of uranium concentrates requirements through at least 1997 from existing contracts. Contracts cover requirements to provide conversion and fabrication through 2016, and enrichment through 2002.

Palo Verde on-site spent fuel storage capacity will accommodate needs through 1999 while maintaining full-core offload reserve. Planned modifications will extend storage capacities with full-core reserve through 2004 for Units 1 and 2 and through 2005 for Unit 3.

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.

The Clean Air Act provides the statutory framework to implement a program for achieving national ambient air quality standards in areas exceeding such standards and provides for maintenance of air quality in areas already meeting such standards. The Clean Air Act was amended in 1990, giving the South Coast Air Quality Management District ("SCAQMD") 20 years to achieve the federal air quality standards for ozone. The SCAQMD's 1997 Air Quality Management Plan ("AQMP") Update, adopted in November 1996, demonstrates a commitment to attain the federal ozone air quality standard by 2010. Consistent with the requirements of the AQMP and the Clean Air Act Amendments of 1990 ("CAAA"), the SCAQMD adopted rules to reduce emissions of oxides of nitrogen ("NOx") from combustion turbines, internal combustion engines, industrial coolers and utility boilers. On October 15, 1993, the SCAQMD adopted the Regional Clean Air Incentives Market ("RECLAIM") which replaces most of the previous rule requirements with a market mechanism for NOx emission trading (trading credits). RECLAIM will, however, require SCE to significantly reduce NOx emissions through retrofit or purchase of trading credits on all basin generation by 2003. In Ventura County, a NOx rule was adopted requiring more than an 88% NOx reduction by June 1996 at all utility boilers. SCE has installed the required NOx controls in Ventura County.

The CAAA does not require any significant additional emissions control expenditures that are identifiable at this time. The amendments call for a five-year study of the sources and causes of regional haze in the southwestern U.S. Also, the Environmental Protection Agency ("EPA") and SCE will conclude a cooperative tracer study of SO_2 emissions from the Mohave Coal Generating Station in late 1997 or mid- to late- 1998. This study is evaluating potential impact from Mohave emissions on haze within Grand Canyon National Park. The extent to which these studies may require sulfur dioxide emissions reductions at the Mohave plant is not known. The acid rain provisions of the amended Clean Air Act also put an annual limit on sulfur dioxide emissions allowed from power plants. SCE has received more sulfur dioxide allowances than it requires for its projected operations. As a result of a petition by Mohave County in the State of Arizona, the Nevada Department of Environmental Protection ("NDEP") studied the impact of the plume from the Mohave plant on the Mohave area air quality. The regulatory outcome required SCE to meet a new lower opacity limit in early 1994. The NDEP reviewed SCE's performance relative to the opacity limit again in 1995 and determined to retain the current standard. Until more definitive information on tracer study results are

available, SCE expects to meet all the present regulations through improved operations at the plant.

The CAAA also requires the EPA to carry out a three-year study of risk to public health from emissions of toxic air contaminants from power plants, and to regulate such emissions only if required. The study has not been completed by EPA to date.

Regulations under the Clean Water Act require permits for the discharge of certain pollutants into waters of the U.S. 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 even more stringent limitations. In order to comply with guidelines and standards applicable to steam electric power plants, SCE incurs additional expenses and capital expenditures. 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 State of California has adopted a policy discouraging the use of fresh water for plant cooling purposes at inland locations. Such a policy, when taken in conjunction with existing federal and state water quality regulations and coastal zone land use restrictions, could substantially increase the difficulty of siting new generating plants anywhere in California.

The Resource Conservation and Recovery Act ("RCRA") provides the statutory authority for the EPA to implement a regulatory program for the safe treatment, recycling, storage and disposal of solid and hazardous wastes. There is an unresolved issue regarding the degree to which coal wastes should be regulated under RCRA. Increased regulation may result in an increase in expenses related to the operation of Mohave.

The Toxic Substances Control Act and accompanying regulations govern the manufacturing, processing, distribution in commerce, use and disposal of polychlorinated biphenyls, a toxic substance used in certain electrical equipment ("PCB waste"). Current costs for disposal of PCB waste 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 undiscounted amounts). While SCE has numerous insurance policies that it believes may provide coverage for some of these liabilities, it does not recognize recoveries in its financial statements until they are realized.

SCE's recorded estimated minimum liability to remediate its 55 identified sites was $114 million at December 31, 1996. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of

identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $211 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental-cleanup costs at 35 of its sites, representing $101 million of SCE's 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 through insurance and other third-party recoveries. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining 20 sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $104 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $8 million. Recorded costs for 1996 were $7 million.

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

SCE's total capital expenditures for environmental protection for the years 1997 through 2001 are projected to be $900 million. These expenditures are mainly for aesthetics treatment, including undergrounding certain transmission and distribution lines.

Item 2. Properties

Existing Generating Facilities

SCE owns and operates 12 oil- and gas-fueled electric generating plants, one diesel-fueled generating plant, 38 hydroelectric plants and an undivided 75.05% interest (1,614 MW net) in Units 2 and 3 at San Onofre. These plants are located in central and southern California. Palo Verde (15.8% SCE-owned, 579 MW net) is located near Phoenix, Arizona. SCE owns a 48% undivided interest (754 MW) in Units 4 and 5 at the Four Corners Generating Station ("Four Corners Project"), a coal-fueled steam electric generating plant in New Mexico. Palo Verde and the Four Corners Project are operated by other utilities. SCE operates and owns a 56% undivided interest (885 MW) in Mohave, which consists of two coal-fueled steam electric generating units in Clark County, Nevada. At year-end 1996, the existing SCE-owned generating capacity (summer effective rating) was comprised of approximately 65% gas, 15% nuclear, 11% coal, 8% hydroelectric and 1% oil.

San Onofre, the Four Corners Project, certain of SCE's substations and portions of its transmission, distribution and communication systems are located on lands of the United States 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.

With certain exceptions, major and certain minor hydroelectric projects with related reservoirs, currently having an effective operating capacity of 1,156 MW and located in whole or in part on lands of the U.S., are owned and operated by SCE under governmental licenses which expire at various times between 1997 and 2026. Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire the project upon payment of specified compensation. When existing licenses expire, 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 referred to above with an aggregate effective operating capacity of 59.1 MW are pending. Annual licenses issued for all SCE projects, whose licenses have expired and are undergoing relicensing, will be renewed until the new licenses are issued.

In 1996, SCE's peak demand was 18,207 MW, set on August 14, 1996. Total area system operating capacity of 21,602 MW was available to SCE at the time of the 1996 peak. SCE's record peak demand of 18,413 MW occurred on August 17, 1992.

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 $3.7 billion principal amount was outstanding at December 31, 1996. 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, affects SCE's right to use such properties in its business, unless the matters with respect to SCE's interest in the Four Corners Project and the related easement and lease referred to below may be so considered.

SCE's rights in the Four Corners Project, which is located on land of The Navajo Nation of Indians under an easement from the United States 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 the Four Corners Project.

SCE Construction Program and Capital Expenditures

Cash required by SCE for its capital expenditures totaled $616 million in 1996, $773 million in 1995, and $982 million in 1994. Construction expenditures for the 1997-2001 period are forecasted at $3.4 billion.

In addition to cash required for construction expenditures for the next five years as discussed above, $1.8 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 2001 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.

On January 10, 1996, the CPUC's decision for SCE's Test Year 1995 GRC rejected a settlement agreement proposed by SCE, San Diego Gas & Electric (SDG&E) and ORA in its original form, but proposed modifications to certain terms related and granted SCE the opportunity to accept the portion of the settlement agreement related to San Onofre Units 2 and 3 with the proposed modifications. The CPUC gave SCE 25 days to prepare a detailed proposal consistent with the policy adopted in its Decision. On February 5, 1996, SCE filed a revised San Onofre Unit 2 and 3 proposal in which it accepted the modifications to certain settlement agreement terms as proposed by the CPUC. The CPUC adopted the revised proposal on April 10, 1996. Under this Proposal, SCE would have recovered its remaining investment in San Onofre Units 2 and 3 at a reduced rate of return (7.35% compared to the current 9.55%), but on an accelerated basis during the eight-year period from the effective date in 1996 through December 31, 2003. Under AB 1890, however, the recovery of the San Onofre remaining investment must be completed by December 31, 2001. In addition, the traditional cost-of-service ratemaking for San Onofre Units 2 and 3 was superseded by incremental cost incentive pricing (ICIP), in which SCE's customers would pay a preset price for each kilowatt-hour of energy generated at San Onofre during the eight-year period. AB 1890 expressly allowed continuation of ICIP pricing through December 31, 2003, the end of the eight-year period. SCE was compensated for the incremental costs required for the continued operation of San Onofre Units 2 and 3 only with revenues earned through the ICIP. However, 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 is not generating power through future ECAC filings. SCE would also continue to collect funds for decommissioning expenses through traditional ratemaking treatment.

In the restructuring decision, the CPUC ordered SCE to file an application by March 29, 1996, requesting a new rate mechanism for its share of the Palo Verde units to be effective January 1, 1997. On February 29, 1996, SCE filed its Palo Verde Proposal Application requesting adoption of a new rate mechanism for Palo Verde consistent with the San Onofre Units 2 and 3 rate mechanism. On November 15, 1996, SCE, ORA and TURN, entered into a settlement agreement regarding SCE's Palo Verde Proposal Application. The settlement retained SCE's proposal to recover its remaining investment in the Palo Verde units by December 31, 2001 at a reduced rate of return (7.35% compared to the current 9.55%) consistent with Assembly Bill 1890, but modified SCE's proposed Palo Verde rate mechanism. Instead of receiving a preset price for each kilowatt-hour of energy generated during that period, as proposed, 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 that case, SCE must demonstrate that the aggregate amount of the costs exceeding the forecast in that year are reasonable. In addition, if the annual Palo Verde site Gross Capacity Factor (GCF) is less than 55% in a calendar year, SCE will bear the burden of proof to demonstrate that the site's operations causing the GCF 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% GCF may be disallowed. The CPUC approved the settlement agreement on December 20, 1996.

Beginning in 2002, power from Palo Verde Units 1, 2 and 3 will be sold at the then-current market prices with 50% of the benefits of such operation given to customers. Likewise, beginning in 2004, power from San Onofre Units 2 and 3 will be sold at the then-current market prices with 50% of the benefits of such operation given to customers.

San Onofre Nuclear Generating Station

In August 1992, the CPUC approved a settlement agreement between SCE and the CPUC's ORA to discontinue operation of Unit 1 at the end of its then-current fuel cycle. As part of the agreement, SCE recovered its remaining investment over a four-year period ending August 1996, earning an 8.98% rate of return on rate base. In November 1992, SCE discontinued operation of Unit 1.

The Units 2 and 3 steam generators have performed relatively well through the first 15 years of operation, with low rates of ongoing tube degradation. During the most recent Unit 2 refueling and inspection outage, however, an increased rate of degradation was identified, resulting in removing 1.8% of the tubes from service. The cumulative total of Unit 2's tubes removed from service is now 5.5%, well below the maximum 10% allowed in the steam generator design before the rating capacity of the unit must be reduced. As a result of the increased degradation, a mid-cycle inspection outage will be conducted in 1998 for Unit 2. Depending on the results of a forthcoming refueling and inspection outage for Unit 3, a mid-cycle inspection outage may be required in 1998 for that unit also.

Palo Verde Nuclear Generating Station

On March 14, 1993, Arizona Public Service Company ("APS"), the operating agent for Palo Verde, manually shut down Unit 2 as a result of a steam generator tube leak. Unit 2 remained shut down and began its scheduled refueling outage on March 19, 1993.

APS performed an extensive inspection of the Unit 2 steam generators prior to the unit's return to service on September 1, 1993. APS determined that intergranular attack/intergranular stress corrosion cracking was a major contributor to the tube leak. Subsequent inspections have revealed similar, though less severe, corrosion in the Unit 1 and Unit 3 steam generators. APS has taken, and indicates it will continue to take, remedial actions that it believes have slowed the rate of steam generator tube degradation in all three units.

Based on latest available data, APS 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. APS has disclosed that it believes it will be economically desirable to replace the Unit 2 steam generators, which have been most affected by tube cracking, in five to ten years. 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. Unanimous approval

of the Palo Verde participants is required for capital improvements, including steam generator replacement. SCE is evaluating APS' analyses, conducting its own review, and has not yet decided whether it supports replacement of the steam generators.

Nuclear Facility Decommissioning

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

Decommissioning costs, which are recovered through customer rates, are recorded as a component of depreciation expense. Decommissioning expense was $148 million in 1996, $151 million in 1995 and $122 million in 1994. The accumulated provision for decommissioning was $949 million at December 31, 1996, and $823 million at December 31, 1995. The estimated costs to decommission San Onofre Unit 1 ($263 million) are recorded as a liability.

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

Nuclear Facility Depreciation

In October 1994, the CPUC authorized SCE to accelerate recovery of its nuclear plant investments by $75 million per year through 2011, with a corresponding deceleration in recovery of its transmission and distribution assets through revised depreciation estimates over their remaining useful lives. Recovery of the San Onofre and Palo Verde nuclear plant investment has been further accelerated by the 1995 GRC decision, industry restructuring, legislation, and the Commission's decision adopting the Palo Verde Settlement.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $8.9 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the U.S. results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $79 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $158 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such premium amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to periodic adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million has also been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued primarily by mutual insurance companies owned by utilities with nuclear facilities. If losses at any nuclear facility covered by these arrangements were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $34 million per year. Insurance premiums are charged to operating expense.

Item 3. Legal Proceedings

QF Litigation

On May 20, 1993, four geothermal QFs filed a lawsuit against SCE in Los Angeles County Superior Court, claiming that SCE underpaid, and continues to underpay, the plaintiffs for energy. SCE denied the allegations in its response to the complaint. The action was brought on behalf of Vulcan/BN Geothermal Power Company, Elmore L.P., Del Ranch L.P., and Leathers L.P., each of which was partially owned by a subsidiary of Edison Mission Energy (a subsidiary of Edison International) at the time of filing. In April 1996, Edison Mission Energy's 50% share in these projects was sold to CalEnergy. In October 1994, plaintiffs submitted an amended complaint to the court to add causes of action for unfair competition and restraint of trade. In July 1995, after several motions to strike had been heard by the court, the plaintiffs served a fourth amended complaint, which omitted the previous claims based on alleged restraint of trade. The plaintiffs allege in the fourth amended complaint that past underpayments have totaled at least $21 million. In other court filings, plaintiffs contend that additional contract payments owing from the beginning of the alleged underpayments through the end of the contract term could total approximately $60 million. Plaintiffs also seek unspecified punitive damages and an injunction to enjoin SCE from "future" unfair competition. After SCE's motion to strike portions of the fourth amended complaint was denied, SCE filed an answer to the fourth amended complaint which denies its material allegations.

On May 1, 1996, the parties entered into an agreement for a settlement of all claims in dispute. Pursuant to the agreement, the specific terms of which are confidential, a settlement amount has been paid and the parties have entered into mutual general releases, with respect to the period before January 1, 1996. The Company intends to seek recovery of this payment through rates. The Company has also agreed, subject to CPUC approval, to increase payments to plaintiffs for specified levels of energy deliveries for the period after December 31, 1995. Plaintiffs have reserved the right to continue the litigation with respect to the period after December 31, 1995, if CPUC approval is not obtained. On August 8, 1996, the Company filed its application with the CPUC for approval of the settlement as it pertains to the period after 1995. On December 20, 1996, the ORA filed a protest to the application. In its protest, the ORA requests that the CPUC not grant the application or, in the alternative, that the CPUC conduct hearings on the application. On January 17, 1997, the Company filed a reply to the ORA's request. On February 27, 1997, a prehearing conference was held, at which time SCE's application was set for hearing to commence on April 23, 1997.

Between January 1994 and October 1994, SCE was named as a defendant in a series of eight lawsuits brought by independent power producers of wind generation. Seven of the lawsuits were filed in Los Angeles County Superior Court and one was filed in Kern County Superior Court. The lawsuits allege SCE incorrectly interpreted contracts with the plaintiffs by limiting fixed energy payments to a single 10-year period rather than beginning a new 10-year period of fixed energy payments for each stage of development. In its responses to the complaints, SCE denied the

plaintiffs' allegations. In each of the lawsuits, the plaintiffs seek declaratory relief regarding the proper interpretation of the contracts. Plaintiffs allege a combined total of approximately $189 million in damages, which includes consequential damages claimed in seven of the eight lawsuits. On March 1, 1995, the court in the lead Los Angeles Superior Court case granted the plaintiffs' motion seeking summary adjudication that the contract language in question is not reasonably susceptible to SCE's position that there is only a single, 10-year period of fixed payments. Following the March 1 ruling, a ninth lawsuit was filed in the Los Angeles Superior Court raising claims similar to those alleged in the first eight. SCE subsequently responded to the complaint in the new lawsuit by denying its material allegations. On April 5, 1995, SCE filed a petition for Writ of Mandate, Prohibition or Other Appropriate Relief, requesting that the Court of Appeal of the State of California, Second Appellate District issue a writ directing the Los Angeles Superior Court to vacate its March 1 order granting summary adjudication. In a decision filed August 9, 1995, the Court of Appeal issued a writ directing that the order be overturned, and a new order be entered denying the motion. In light of the Court of Appeal decision in the lead Los Angeles case, a summary adjudication motion in the Kern County case was withdrawn. Furthermore, pursuant to stipulation of the parties, the Kern County case was ordered on April 3, 1996, to be coordinated with the Los Angeles cases so that it too will be tried in Los Angeles. On March 25, 1996, pursuant to a court-approved stipulation, all but one of the cases were consolidated for trial in Los Angeles Superior Court. Trial on the consolidated cases is set to begin on March 11, 1997. No trial date has been set in the ninth unconsolidated case.

Environmental Litigation

Electric and Magnetic Fields ("EMF")

SCE is involved in three lawsuits alleging that various plaintiffs developed cancer as a result of exposure to EMF from SCE facilities. SCE denied the material allegations in its responses to each of these lawsuits.

The first lawsuit was filed in Orange County Superior Court and served on SCE in June 1994. There are five named plaintiffs and six named defendants, including SCE. Three of the five plaintiffs are presently or were formerly employed by Grubb & Ellis, a real estate brokerage firm with offices located in a commercial building known as the Koll Center in Newport Beach. Two of the named plaintiffs are spouses of the other plaintiffs. Grubb & Ellis and the owners and developers of the Koll Center are also named as defendants in the lawsuit. This lawsuit alleges, among other things, that the three plaintiffs employed by Grubb & Ellis developed various forms of cancer as a result of exposure to EMF from electrical facilities owned by SCE and/or the other defendants located on Koll Center property. No specific damage amounts are alleged in the complaint, but supplemental documentation prepared by the plaintiffs indicates that plaintiffs allege compensatory damages of approximately $8 million, plus unspecified punitive damages. In December 1995, the court granted SCE's motion for summary judgment and dismissed the case. Plaintiffs have filed a Notice of Appeal. Briefs have been submitted but no date for oral argument has been set.

A second lawsuit was filed in Orange County Superior Court and served on SCE in January 1995. This lawsuit arises out of the same fact situation as the June 1994 lawsuit described above and involves the same defendants. There are four named plaintiffs, two of whom were formerly employed by Grubb & Ellis and now allegedly have various forms of cancer. The other two plaintiffs are the spouses of those two individuals. No specific damage amounts are alleged in the complaint, but supplemental documentation prepared by the plaintiffs indicates that plaintiffs will allege compensatory damages of approximately $13.5 million, plus unspecified punitive damages. On April 18, 1995, Grubb & Ellis filed a

cross-complaint against the other co-defendants, requesting indemnification and declaratory relief concerning the rights and responsibilities of the parties. This case has been stayed pending appellate review of the trial judge's sanction order against the plaintiffs' attorneys. The Court of Appeals has heard oral argument on this issue, but no decision has been issued.

A third case was filed in Orange County Superior Court and served on SCE in March 1995. The plaintiff alleges, among other things, that he developed cancer as a result of EMF emitted from SCE distribution lines which he alleges were not constructed in accordance with CPUC standards. No specific damage amounts are alleged in the complaint but supplemental documentation prepared by the plaintiff indicates that plaintiff will allege compensatory damages of approximately $5.5 million, plus unspecified punitive damages. No trial date has been set in this case.

San Onofre Personal Injury Litigation

An SCE engineer employed at San Onofre died in 1991 from cancer of the abdomen. On February 6, 1995, his children sued SCE and SDG&E, as well as Combustion Engineering, the manufacturer of the fuel rods for the plant, in the U.S. District court for the Southern District of California. Plaintiffs alleged that the former employee's illness resulted from, and was aggravated by, exposure to radiation at San Onofre, including contact with radioactive fuel particles released from failed fuel rods. Plaintiffs sought unspecified compensatory and punitive damages. On April 3, 1995, the court granted the defendants' motion to dismiss 14 of the plaintiffs' claims. SCE's April 20, 1995, answer to the complaint denied all material allegations. On October 10, 1995, the court granted plaintiffs' motion to include the Institute of Nuclear Power Operations (an organization dedicated to achieving excellence in nuclear power operations) as a defendant in the suit. On December 7, 1995, the court granted SCE's motion for summary judgment on the sole outstanding claim against it, basing the ruling on the worker's compensation system being the exclusive remedy for the claim. Plaintiffs have appealed this ruling to the Ninth Circuit Court of Appeals. All trial court proceedings have been stayed pending the ruling of the Court of Appeals. The impact to SCE, if any, from further proceedings in this case against the remaining defendants cannot be determined at this time.

On July 5, 1995, a former SCE reactor operator and his wife sued SCE and SDG&E in the U.S. District court for the Southern District of California. Plaintiffs also named Combustion Engineering, the manufacturer of the fuel rods for the plant, and the Institute of Nuclear Power Operations as defendants. The former employee died of leukemia shortly after the complaint was filed. Plaintiffs allege that the former operator's illness resulted from, and was aggravated by, exposure to radiation at San Onofre, including contact with radioactive fuel particles released from failed fuel rods. Plaintiffs seek unspecified compensatory and punitive damages. On November 22, 1995, the complaint was amended to allege wrongful death and added the former employee's two children as plaintiffs. On December 22, 1995, SCE filed a motion to dismiss or, in the alternative, for summary judgment based on worker's compensation exclusivity. On March 25, 1996, the court granted SCE's motion for summary judgment. Plaintiffs have appealed this ruling to the Ninth Circuit Court of Appeals. All trial court proceedings have been stayed pending the ruling of the Court of Appeals in this case and in the case described in the above paragraph. The impact to SCE, if any, from further proceedings in this case against the remaining defendants cannot be determined at this time.

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, the manufacturer of fuel rods for the plant, and the Institute of Nuclear Power Operations as defendants. The security officer worked for a contractor in 1982, worked for SCE as a temporary employee (1982-1984),

and later worked as an SCE security supervisor (1984-1994). The officer died of leukemia in 1994. Plaintiffs allege that the former officer's illness resulted from, and was aggravated by, his exposure to radiation at San Onofre, including contact with radioactive fuel particles released from failed fuel rods. Plaintiffs seek unspecified compensatory and punitive damages. SCE's November 13, 1995, answer to the complaint denied all material allegations. All trial court proceedings have been stayed pending the rulings of the Court of Appeals in the cases described in the above two paragraphs.

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 manufacturer of the fuel rods for the San Onofre plant. The employee worked for SCE at San Onofre from 1981 to 1990. Plaintiffs alleged that the employee transported radioactive byproducts on his person, clothing and/or tools to his home where his wife was then exposed to radiation that caused her leukemia. Plaintiffs seek unspecified compensatory and punitive damages. SCE's December 19, 1995, partial answer to the complaint denied all material non-employment related allegations. SCE's motion to dismiss the employee's employment related allegations based on worker's compensation exclusivity was granted on March 19, 1996. The employee's wife died on August 15, 1996. On September 20, 1996, the complaint was amended to allege wrongful death and to add the employee's two children as plaintiffs. The trial is expected to begin in August 1997.

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, the manufacturer of the fuel rods for the San Onofre plant. Plaintiffs allege that the former contract worker transported radioactive byproducts on her person and clothing to her home where her son was then exposed to radiation that caused his leukemia. Plaintiffs seek unspecified compensatory and punitive damages. SCE's January 2, 1996, answer denied all material allegations. On August 12, 1996, the Court dismissed the claims of the former worker and her husband with prejudice. The case is expected to go to trial in late 1997.

Employment Discrimination Litigation

On September 21, 1994, nine African-American employees filed a lawsuit against Edison International and SCE on behalf of a class of African-American employees, alleging racial discrimination in job advancement, pay, training and evaluation. The lawsuit was filed in the United States District Court for the Central District of California. The plaintiffs sought injunctive relief, as well as an unspecified amount of compensatory and punitive damages, attorneys' fees, costs and interest. Edison International and SCE responded by denying the material allegations of the complaint and asserting several affirmative defenses.

Simultaneous with discovery, the parties entered into settlement discussions. The parties agreed to include the Equal Employment Opportunity Commission (EEOC) in their settlement discussions after that agency indicated its intent to intervene in the lawsuit in support of the plaintiffs. The parties and EEOC agreed upon settlement terms and submitted a proposed Consent Decree to the court for approval. After certain issues raised by the court were addressed through a modification of the proposed Decree, the court granted preliminary approval of the modified Consent Decree on August 5, 1996, ordered that notice be given to the class members, and scheduled a final fairness hearing on September 26, 1996.

Fifteen individuals and an organization filed timely objections to the proposed Consent Decree and a motion to intervene in the lawsuit. Thirteen individuals filed timely requests to be excluded from the monetary provisions of the proposed Decree. On September 25, 1996, the court denied the motion to intervene. After the hearing on September 26,

at which the court heard oral argument from the objectors, the court on September 30, 1996, overruled the objections and granted final approval of the Consent Decree.

The Decree provides that a settlement fund of $8.15 million for back pay claims and $3.1 million for emotional distress claims be established, and it contains an expedited claim review process for class members who make claims to the settlement fund. The Decree also provides for improvements in the Company's internal claims resolution process, expansion of career development and skills training programs, expansion of diversity training programs, and improvements in other human resources systems. The Decree has a seven-year term, with the possibility of early termination after five years.

On October 25, 1996, the organization and individuals who sought to intervene and/or object to the Consent Decree served notice of appeal from the court's orders denying intervention and approving the Consent Decree. The Court of Appeals ordered that the appellants file their opening brief by March 12, 1997, and that appellees file any responsive brief by April 11, 1997. Appellants have moved for an extension of time to file their opening brief, but that motion has not been ruled upon and appellants have not yet filed their brief.

Oil Pipeline Litigation

On November 1, 1996, plaintiff, a crude oil pipeline company, filed a lawsuit against SCE and the City of Los Angeles (the "City") in the United States District Court for the Central District of California claiming that SCE and the City had interfered with its attempt to construct a proposed 132-mile oil pipeline ("Pacific Pipeline") designed to transport oil from the San Joaquin Valley and Santa Barbara to the Los Angeles refineries.

Plaintiff alleges, among other things, that SCE and the City wrongfully initiated administrative and other legal proceedings in an attempt to derail and obstruct the construction of the Pacific Pipeline. Plaintiff alleges that these acts constitute unfair competition, tortious interference with economic advantage and violate state and federal antitrust laws. Plaintiff further claims that because of the alleged delays, it could suffer losses in excess of $300 million. Additionally, plaintiff seeks treble and punitive damages.

The deadline for filing a response to the complaint has been continued pending the outcome of a motion by plaintiff filed in a related lawsuit seeking to dismiss the City of Los Angeles' complaint therein against the U.S. Forest Service and plaintiff. SCE intends to deny the substantive allegations of the complaint.

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, 1996	Company Position[2]	Effective Date
John E. Bryson	53	Chairman of the Board, Chief Executive Officer and Director	October 1, 1990
Stephen E. Frank	55	President, Chief Operating Officer and Director	June 19, 1995

Bryant C. Danner	59	Executive Vice President and General Counsel	June 1, 1995
Alan J. Fohrer	46	Executive Vice President and Chief Financial Officer	September 1, 1996
Harold B. Ray	56	Executive Vice President, Generation Business Unit	June 1, 1995
Vikram S. Budhraja	49	Senior Vice President, Power Grid Business Unit	June 1, 1995
Robert G. Foster	49	Senior Vice President, Public Affairs	November 21, 1996
Emiko Banfield	50	Vice President, Shared Services	July 22, 1996
Pamela A. Bass	49	Vice President, Customer Solutions Business Unit	June 1, 1996
Richard K. Bushey	56	Vice President and Controller	January 1, 1984
Theodore F. Craver, Jr.	45	Vice President and Treasurer	September 1, 1996
John R. Fielder	51	Vice President, Regulatory Policy and Affairs	February 1, 1992
Bruce C. Foster	44	Vice President, San Francisco Regulatory Affairs	January 1, 1995
Lillian R. Gorman	43	Vice President, Human Resources	July 22, 1996
Lawrence D. Hamlin	52	Vice President, Power Production	February 1, 1992
Thomas J. Higgins	51	Vice President, Corporate Communications	April 1, 1995
R. W. Krieger	48	Vice President, Nuclear Generation	June 17, 1993
J. Michael Mendez	55	Vice President, Labor Relations	February 10, 1997
Dwight E. Nunn	54	Vice President, Nuclear Engineering and Technical Services	December 18, 1995
Frank J. Quevedo	52	Vice President, Equal Opportunity	June 1, 1996
Richard M. Rosenblum	46	Vice President, Distribution Business Unit	January 1, 1996
Beverly P. Ryder	46	Corporate Secretary and Special Assistant to the Chairman/CEO	January 1, 1996

(1) Ron Daniels, Vice President of Special Projects, retired on April 1, 1996. On June 1, 1996, Owens F. Alexander left his position as SCE Vice President of Customer Solutions, to become Senior Vice President for Edison Source.

On June 1, 1996, Pamela A. Bass became Vice President of Customer Solutions Business Unit and Frank J. Quevedo was elected Vice President of Equal Opportunity. On July 22, 1996, Emiko Banfield

became Vice President of Shared Services, and Lillian R. Gorman was elected Vice President of Human Resources. Theodore F. Craver, Jr. was elected Vice President and Treasurer on September 1, 1996. On November 21, 1996, Robert G. Foster was elected Senior Vice President of Public Affairs. On February 10, 1997, J. Michael Mendez became Vice President of Labor Relations.

(2) Executive officers Bryson, Danner, Fohrer, Robert Foster, Bushey, Craver, Gorman, Higgins, and Ryder hold the same positions with Edison International. Edison International is the parent holding company of SCE.

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 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, Bryant C. Danner, Theodore F. Craver, Jr., Bruce C. Foster, Lillian R. Gorman, Thomas J. Higgins, Dwight E. Nunn, Frank J. Quevedo and Beverly P. Ryder. Those officers who have not held their present position for the past five years had the following business experience:

Stephen E. Frank	President and Chief Operating Officer, Florida Power and Light Company[4]	August 1990 to January 1995
Bryant C. Danner	Senior Vice President and General Counsel of Edison International and SCE	July 1992 to May 1995
	Partner with the Law Firm of Latham & Watkins[1][4]	January 1970 to June 1992
Alan J. Fohrer	Executive Vice President, Chief Financial Officer and Treasurer of SCE	February 1996 to August 1996
	Executive Vice President and Chief Financial Officer of SCE	May 1995 to January 1996
	Executive Vice President, Chief Financial Officer and Treasurer of Edison International	May 1995 to August 1996
	Senior Vice President, Chief Financial Officer and Treasurer of Edison International	January 1993 to April 1995
	Senior Vice President and Chief Financial Officer of SCE	January 1993 to April 1995
	Vice President, Chief Financial Officer and Treasurer of Edison International and SCE	April 1991 to January 1993
Harold B. Ray	Senior Vice President, Power Systems	June 1990 to May 1995
Robert G. Foster	Vice President, Public Affairs	November 1993 to October 1996
	Regional Vice President, Sacramento Office	January 1988 to October 1993
Vikram S. Budhraja	Vice President, Planning and Technology	June 1993 to May 1995
	Vice President, System Planning and Operations	February 1992 to May 1993
Emiko Banfield	Vice President, Human Resources	January 1996 to July 1996
	Manager of Procurement and Material Management	May 1994 to December 1995
	Manager of Transportation Services	December 1991 to May 1994
Pamela A. Bass	Vice President, Shared Services	January 1996 to May 1996
	Division Vice President, ENvest[3]	August 1993 to December 1995
	Division Vice President, Customer Services	January 1992 to August 1993

Theodore F. Craver, Jr.	Executive Vice President and Corporate Treasurer, First Interstate Bancorp	September 1990 to August 1996
Bruce C. Foster	Regional Vice President, San Francisco Office	January 1992 to December 1994
Lillian R. Gorman	Executive Vice President and Human Resources Director, First Interstate Bancorp	October 1990 to July 1996
Thomas J. Higgins	President, The Laurel Company(2)(4) Senior Vice President of Blue Cross/Blue Shield of Maryland(4)	January 1994 to December 1994 October 1990 to December 1993
R. W. Krieger	Station Manager, San Onofre	August 1990 to May 1993
J. Michael Mendez	Vice President, Regional Leadership Vice President, Human Resources	February 1993 to January 1997 August 1991 to January 1993
Dwight E. Nunn	Vice President, Tennessee Valley Authority(4)	April 1990 to December 1995
Frank J. Quevedo	Director of Equal Opportunity Manager of Equal Opportunity Director, Corporate Relations, Hunt-Wesson, Inc.	January 1996 to May 1996 July 1992 to December 1995 June 1986 to June 1992
Richard M. Rosenblum	Vice President, Engineering and Technical Services Manager of Nuclear Regulatory Affairs	June 1993 to December 1995 June 1989 to May 1993
Beverly P. Ryder	Special Assistant to the Chairman of Edison International and SCE Director, Strategic Alliances, EnvestSCE(3) General Manager, Customer Solutions Vice President, Corporate Asset Funding, Citibank, N.A.(4)	May 1995 to December 1995 October 1993 to April 1995 June 1992 to September 1993 April 1985 to June 1992

(1) Prior to leaving the law firm of Latham & Watkins, Mr. Danner was in the firm's environmental department.

(2) As President of The Laurel Company, Thomas J. Higgins provided advice on planning and financing for mergers and acquisitions for clients in the managed health care business.

(3) This entity is a division of SCE.

(4) 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, 1996, ("Annual Report") under "Quarterly Financial Data" on page 31 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: 1992-1996" on page 1 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 2 through 10 and is incorporated herein by reference pursuant to General Instruction G(2).

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, 12, 13, and 14 through 31 under "Quarterly Financial Data", 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 Edison International 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 Commission in connection with SCE's Annual Meeting to be held on April 17, 1997, under the heading, "Election of Directors of Edison International and SCE" on pages 2 through 6 and "Section 16(a) Beneficial Ownership Reporting Compliance" on page 22, 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 Table - Edison International and SCE" on pages 9 through 21, 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 of Edison International and SCE" on pages 7 through 10 and "Stock Ownership of Certain Shareholders" on page 25, 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 Additional Affiliations and Transactions of Nominees and Executive Officers" on pages 22 through 25, 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 1996 Annual Report to Shareholders are 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, 1996, 1995 and 1994
Consolidated Statements of Retained Earnings -- Years Ended December 31, 1996, 1995 and 1994
Consolidated Balance Sheets -- December 31, 1996, and 1995
Consolidated Statements of Cash Flows -- Years Ended December 31, 1996, 1995 and 1994
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, 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

January 18, 1996
Item 5: Other Events: Announcement of 1995 4th Quarter Earnings

October 3, 1996
Item 5: Other Events: Governor Wilson Signs Assembly Bill 1890

December 5, 1996
Item 5: Other Events: Divestiture of 12 natural gas and oil-fueled power plants

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SUPPLEMENTAL SCHEDULES

To Southern California Edison Company:

We have audited in accordance with generally accepted auditing standards, the consolidated financial statements included in the 1996 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 January 31, 1997. 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
January 31, 1997 (except with respect
to the "Subsequent Event" discussed under
"Competitive Environment" in Part I, Item 1,
as to which the date is February 21, 1997)

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1996

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	$ 22,126	$ 21,831	$ --	$ 19,567	$ 24,390
All other	2,013	376	--	700	1,689
Total	$ 24,139	$ 22,207	$ --	$ 20,267(a)	$ 26,079
Group B:					
DOE decontamination and decommissioning	$ 52,742	$ --	$ 1,468(b)	$ 5,421(c)	$ 48,789
Purchase Power Settlement	--	--	107,700(d)	--	107,700
Pension and benefits	196,662	8,547	21,869(e)	46,151(f)	180,927
Insurance, casualty and other	94,788	59,123	--	67,402(g)	86,509
Total	$344,192	$67,670	$131,037	$118,974	$423,925

(a) Accounts written off, net.

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

(c) Represents amounts paid.

(d) Represents payments to be made under agreement to terminate a purchase-power contract.

(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, 1995

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	$ 21,000	$ 22,179	$ --	$ 21,053	$ 22,126
All other	2,806	801	--	1,594	2,013
Total	$ 23,806	$ 22,980	$ --	$ 22,647(a)	$ 24,139
Group B:					
DOE Decontamination and Decommissioning	$ 56,485	$ --	$ 1,531(b)	$ 5,274(c)	$ 52,742
Pension and benefits	174,851	42,805	23,931(d)	44,670(e)	196,662
Insurance, casualty and other	79,727	74,751	--	56,690(f)	94,788
Total	$311,063	$117,556	$25,207	$109,634	$344,192

(a) Accounts written off, net.

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

(c) Represents amounts paid.

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

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

(f) 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, 1994

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	$ 15,664	$ 27,071	$ --	$ 21,735	$ 21,000
All other	2,758	1,428	--	1,380	2,806
Total	$ 18,422	$ 28,499	$ --	$ 23,115(a)	$ 23,806
Group B:					
DOE Decontamination and Decommissioning	$ 67,128	$ --	$ (452)(b)	$ 10,191(c)	$ 56,485
Pension and benefits	131,764	147,037	23,931 (d)	127,881(e)	174,851
Insurance, casualty and other	67,703	67,197	--	55,173(f)	79,727
Total	$266,595	$214,234	$23,479	$193,245	$311,063

(a) Accounts written off, net.

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

(c) Represents amounts paid.

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

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

(f) 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 Timothy W. Rogers

Timothy W. Rogers
Attorney

Date: March 27, 1997

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:		
John E. Bryson*	Chairman of the Board, Chief Executive Officer and Director	March 27, 1997
Principal Financial Officer:		
Alan J. Fohrer*	Executive Vice President and Chief Financial Officer	March 27, 1997
Controller or Principal Accounting Officer:		
Richard K. Bushey*	Vice President and Controller	March 27, 1997
Board of Directors:		
Howard P. Allen*	Director	March 27, 1997
Winston H. Chen*	Director	March 27, 1997
Stephen E. Frank*	Director	March 27, 1997
Camilla C. Frost*	Director	March 27, 1997
Joan C. Hanley*	Director	March 27, 1997
Carl F. Huntsinger*	Director	March 27, 1997
Charles D. Miller*	Director	March 27, 1997
Luis G. Nogales*	Director	March 27, 1997
Ronald L. Olson*	Director	March 27, 1997
J. J. Pinola*	Director	March 27, 1997
James M. Rosser*	Director	March 27, 1997
E. L. Shannon, Jr.*	Director	March 27, 1997
Robert H. Smith*	Director	March 27, 1997
Thomas C. Sutton*	Director	March 27, 1997
Daniel M. Tellep*	Director	March 27, 1997
James D. Watkins*	Director	March 27, 1997
Edward Zapanta*	Director	March 27, 1997

*By Timothy W. Rogers

Timothy W. Rogers, Attorney-in-fact

EXHIBIT INDEX

Exhibit Number	Description
3.1	Restated Articles of Incorporation as amended through January 1996 (File No. 1-2313)*
3.2	Bylaws as adopted by the Board of Directors on February 15, 1996
4.1	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	Second Supplemental Indenture, dated as of April 25, 1935 (Registration No. 2-1472)*
4.4	Third Supplemental Indenture, dated as of June 24, 1935 (Registration No. 2-1602)*
4.5	Fourth Supplemental Indenture, dated as of September 1, 1935 (Registration No. 2-4522)*
4.6	Fifth Supplemental Indenture, dated as of August 15, 1939 (Registration No. 2-4522)*
4.7	Sixth Supplemental Indenture, dated as of September 1, 1940 (Registration No. 2-4522)*
4.8	Seventh Supplemental Indenture, dated as of January 15, 1948 (Registration No. 2-7369)*
4.9	Eighth Supplemental Indenture, dated as of August 15, 1948 (Registration No. 2-7610)*
4.10	Ninth Supplemental Indenture, dated as of February 15, 1951 (Registration No. 2-8781)*
4.11	Tenth Supplemental Indenture, dated as of August 15, 1951 (Registration No. 2-7968)*
4.12	Eleventh Supplemental Indenture, dated as of August 15, 1953 (Registration No. 2-10396)*
4.13	Twelfth Supplemental Indenture, dated as of August 15, 1954 (Registration No. 2-11049)*
4.14	Thirteenth Supplemental Indenture, dated as of April 15, 1956 (Registration No. 2-12341)*
4.15	Fourteenth Supplemental Indenture, dated as of February 15, 1957 (Registration No. 2-13030)*
4.16	Fifteenth Supplemental Indenture, dated as of July 1, 1957 (Registration No. 2-13418)*
4.17	Sixteenth Supplemental Indenture, dated as of August 15, 1957 (Registration No. 2-13516)*
4.18	Seventeenth Supplemental Indenture, dated as of August 15, 1958 (Registration No. 2-14285)*
4.19	Eighteenth Supplemental Indenture, dated as of January 15, 1960 (Registration No. 2-15906)*
4.20	Nineteenth Supplemental Indenture, dated as of August 15, 1960 (Registration No. 2-16820)*
4.21	Twentieth Supplemental Indenture, dated as of April 1, 1961 (Registration No. 2-17668)*
4.22	Twenty-First Supplemental Indenture, dated as of May 1, 1962 (Registration No. 2-20221)*
4.23	Twenty-Second Supplemental Indenture, dated as of October 15, 1962 (Registration No. 2-20791)*
4.24	Twenty-Third Supplemental Indenture, dated as of May 15, 1963 (Registration No. 2-21346)*
4.25	Twenty-Fourth Supplemental Indenture, dated as of February 15, 1964 (Registration No. 2-22056)*

EXHIBIT INDEX

Exhibit Number	Description
4.26	Twenty-Fifth Supplemental Indenture, dated as of February 1, 1965 (Registration No. 2-23082)*
4.27	Twenty-Sixth Supplemental Indenture, dated as of May 1, 1966 (Registration No. 2-24835)*
4.28	Twenty-Seventh Supplemental Indenture, dated as of August 15, 1966 (Registration No. 2-25314)*
4.29	Twenty-Eighth Supplemental Indenture, dated as of May 1, 1967 (Registration No. 2-26323)*
4.30	Twenty-Ninth Supplemental Indenture, dated as of February 1, 1968 (Registration No. 2-28000)*
4.31	Thirtieth Supplemental Indenture, dated as of January 15, 1969 (Registration No. 2-31044)*
4.32	Thirty-First Supplemental Indenture, dated as of October 1, 1969 (Registration No. 2-34839)*
4.33	Thirty-Second Supplemental Indenture, dated as of December 1, 1970 (Registration No. 2-38713)*
4.34	Thirty-Third Supplemental Indenture, dated as of September 15, 1971 (Registration No. 2-41527)*
4.35	Thirty-Fourth Supplemental Indenture, dated as of August 15, 1972 (Registration No. 2-45046)*
4.36	Thirty-Fifth Supplemental Indenture, dated as of February 1, 1974 (Registration No. 2-50039)*
4.37	Thirty-Sixth Supplemental Indenture, dated as of July 1, 1974 (Registration No. 2-59199)*
4.38	Thirty-Seventh Supplemental Indenture, dated as of November 1, 1974 (Registration No. 2-52160)*
4.39	Thirty-Eighth Supplemental Indenture, dated as of March 1, 1975 (Registration No. 2-52776)*
4.40	Thirty-Ninth Supplemental Indenture, dated as of March 15, 1976 (Registration No. 2-55463)*
4.41	Fortieth Supplemental Indenture, dated as of July 1, 1977 (Registration No. 2-59199)*
4.42	Forty-First Supplemental Indenture, dated as of November 1, 1978 (Registration No. 2-62609)*
4.43	Forty-Second Supplemental Indenture, dated as of June 15, 1979 (File No. 1-2313)*
4.44	Forty-Third Supplemental Indenture, dated as of September 15, 1979 (File No. 1-2313)*
4.45	Forty-Fourth Supplemental Indenture, dated as of October 1, 1979 (Registration No. 2-65493)*
4.46	Forty-Fifth Supplemental Indenture, dated as of April 1, 1980 (Registration No. 2-66896)*
4.47	Forty-Sixth Supplemental Indenture, dated as of November 15, 1980 (Registration No. 2-69609)*
4.48	Forty-Seventh Supplemental Indenture, dated as of May 15, 1981 (Registration No. 2-71948)*
4.49	Forty-Eighth Supplemental Indenture, dated as of August 1, 1981 (File No. 1-2313)*
4.50	Forty-Ninth Supplemental Indenture, dated as of December 1, 1981 (Registration No. 2-74339)*
4.51	Fiftieth Supplemental Indenture, dated as of January 16, 1982 (File No. 1-2313)*
4.52	Fifty-First Supplemental Indenture, dated as of April 15, 1982 (Registration No. 2-76626)*

EXHIBIT INDEX

Exhibit Number	Description
4.53	Fifty-Second Supplemental Indenture, dated as of November 1, 1982 (Registration No. 2-79672)*
4.54	Fifty-Third Supplemental Indenture, dated as of November 1, 1982 (File No. 1-2313)*
4.55	Fifty-Fourth Supplemental Indenture, dated as of January 1, 1983 (File No. 1-2313)*
4.56	Fifty-Fifth Supplemental Indenture, dated as of May 1, 1983 (File No. 1-2313)*
4.57	Fifty-Sixth Supplemental Indenture, dated as of December 1, 1984 (Registration No. 2-94512)*
4.58	Fifty-Seventh Supplemental Indenture, dated as of March 15, 1985 (Registration No. 2-96181)*
4.59	Fifty-Eighth Supplemental Indenture, dated as of October 1, 1985 (File No. 1-2313)*
4.60	Fifty-Ninth Supplemental Indenture, dated as of October 15, 1985 (File No. 1-2313)*
4.61	Sixtieth Supplemental Indenture, dated as of March 1, 1986 (File No. 1-2313)*
4.62	Sixty-First Supplemental Indenture, dated as of March 15, 1986 (File No. 1-2313)*
4.63	Sixty-Second Supplemental Indenture, dated as of April 15, 1986 (File No. 1-2313)*
4.64	Sixty-Third Supplemental Indenture, dated as of April 15, 1986 (File No. 1-2313)*
4.65	Sixty-Fourth Supplemental Indenture, dated as of July 1, 1986 (File No. 1-2313)*
4.66	Sixty-Fifth Supplemental Indenture, dated as of September 1, 1986 (File No. 1-2313)*
4.67	Sixty-Sixth Supplemental Indenture, dated as of September 1, 1986 (File No. 1-2313)*
4.68	Sixty-Seventh Supplemental Indenture, dated as of December 1, 1986 (File No. 1-2313)*
4.69	Sixty-Eighth Supplemental Indenture, dated as of July 1, 1987 (Registration No. 33-19541)*
4.70	Sixty-Ninth Supplemental Indenture, dated as of October 15, 1987 (Registration No. 33-19541)*
4.71	Seventieth Supplemental Indenture, dated as of November 1, 1987 (File No. 1-2313)*
4.72	Seventy-First Supplemental Indenture, dated as of February 15, 1988 (File No. 1-2313)*
4.73	Seventy-Second Supplemental Indenture, dated as of April 15, 1988 (File No. 1-2313)*
4.74	Seventy-Third Supplemental Indenture, dated as of July 1, 1988 (File No. 1-2313)*
4.75	Seventy-Fourth Supplemental Indenture, dated as of August 15, 1988 (File No. 1-2313)*
4.76	Seventy-Fifth Supplemental Indenture, dated as of September 15, 1988 (File No. 1-2313)*
4.77	Seventy-Sixth Supplemental Indenture, dated as of January 15, 1989 (File No. 1-2313)*
4.78	Seventy-Seventh Supplemental Indenture, dated as of May 1, 1990 (File No. 1-2313)*
4.79	Seventy-Eighth Supplemental Indenture, dated as of June 15, 1990 (File No. 1-2313)*
4.80	Seventy-Ninth Supplemental Indenture, dated as of August 15, 1990 (File No. 1-2313)*
4.81	Eightieth Supplemental Indenture, dated as of December 1, 1990 (File No. 1-2313)*

EXHIBIT INDEX

Exhibit Number	Description
4.82	Eighty-First Supplemental Indenture, dated as of April 1, 1991 (File No. 1-2313)*
4.83	Eighty-Second Supplemental Indenture, dated as of May 1, 1991 (File No. 1-2313)*
4.84	Eighty-Third Supplemental Indenture, dated as of June 1, 1991 (File No. 1-2313)*
4.85	Eighty-Fourth Supplemental Indenture, dated as of December 1, 1991 (File No. 1-2313)*
4.86	Eighty-Fifth Supplemental Indenture, dated as of February 1, 1992 (File No. 1-2313)*
4.87	Eighty-Sixth Supplemental Indenture, dated as of April 1, 1992 (File No. 1-2313)*
4.88	Eighty-Seventh Supplemental Indenture, dated as of July 1, 1992 (File No. 1-2313)*
4.89	Eighty-Eighth Supplemental Indenture, dated as of July 15 1992 (File No. 1-2313)*
4.90	Eighty-Ninth Supplemental Indenture, dated as of December 1, 1992 (File No. 1-2313)*
4.91	Ninetieth Supplemental Indenture, dated as of January 15, 1993 (File No. 1-2313)*
4.92	Ninety-First Supplemental Indenture, dated as of March 1, 1993 (File No. 1-2313)*
4.93	Ninety-Second Supplemental Indenture, dated as of June 1, 1993*
4.94	Ninety-Third Supplemental Indenture, dated as of June 15, 1993 (File No. 1-2313)*
4.95	Ninety-Fourth Supplemental Indenture, dated as of July 15, 1993 (File No. 1-2313)*
4.96	Ninety-Fifth Supplemental Indenture, dated as of September 1, 1993 (File No. 1-2313)*
4.97	Ninety-Sixth Supplemental Indenture, dated as of October 1, 1993 (File No. 1-2313)*

EXHIBIT INDEX

Exhibit Number	Description
10.1	1981 Deferred Compensation Agreement (File No. 1-2313)*
10.2	1985 Deferred Compensation Agreement for Executives (File No. 1-2313)*
10.3	1985 Deferred Compensation Agreement for Directors (File No. 1-2313)*
10.4	Director Deferred Compensation Plan (File No. 1-9936)*
10.5	Director Grantor Trust Agreement (File No. 1-9936)*
10.6	Executive Deferred Compensation Plan (File No. 1-9936)*
10.7	Executive Grantor Trust Agreement (File No. 1-9936)*
10.8	Executive Supplemental Benefit Program (File No. 1-2313)*
10.9	Executive Retirement Plan (File No. 1-2313)*
10.10	Employment Agreement with Howard P. Allen (File No. 1-2313)*
10.11	1995 Executive Incentive Compensation Plan (File No. 1-9936)*
10.12	1996 Executive Incentive Compensation Plan
10.13	Executive Disability and Survivor Benefit Program (File No. 1-9936)*
10.14	Retirement Plan for Directors
10.15	Director Incentive Compensation Plan
10.16	Officer Long-Term Incentive Compensation Plan
10.16.1	Form of Agreement for 1989-1995 Awards under the Officer Long-Term Incentive Compensation Plan (File No. 1-9936)*
10.16.2	Form of Agreement for 1996 Awards under the Officer Long-Term Incentive Compensation Plan
10.17	Estate and Financial Planning Program (File No. 1-9936)*
10.18	Consulting Agreement with Howard P. Allen (File No. 1-9936)*
10.19	Employment Agreement with Bryant C. Danner (File No. 1-9936)*
10.20	Employment Agreement with Stephen E. Frank (File No. 1-9936)*
12.	Computation of Ratios of Earnings to Fixed Charges
13.	Annual Report to Shareholders for year ended December 31, 1996
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.

SOUTHERN CALIFORNIA EDISON COMPANY

1997 Internal Cash Flow Projection

(Dollars in Thousands)

	1996 Actual	1997 Projected
Net Income After Taxes	$655,395	(*)
Dividends Paid	$799,593	(*)
Retained Earnings	($144,198)	(*)
Adjustments:		
Depreciation & Decommissioning	$1,063,505	$1,290,000
Net Deferred Taxes & ITC	$46,122	$15,000
Allowance for Funds Used During Construction	($25,373)	($23,000)
Total Adjustments	$1,084,254	$1,282,000
Internal Cash Flow	$940,056	(*)
Average Quarterly Cash Flow	$235,014	(*)
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	

(*) Company policy prohibits disclosure of financial data which will enable unauthorized persons to forecast earnings or dividends, unless assured confidentiality. The Net Projected Cash Flow for 1997 is expected to be comparable to the Actual Cash Flow for 1996.

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6/10/97