nrc w/ltr 4/13/84

Southern California Edison Company 1983 Annual Report

From the Old to the New: An Innovative Transition

Southern California Edison Company

Hydroelectric

Fossil
(oil, gas, coal)

Nuclear

Geothermal

Wind

Solar

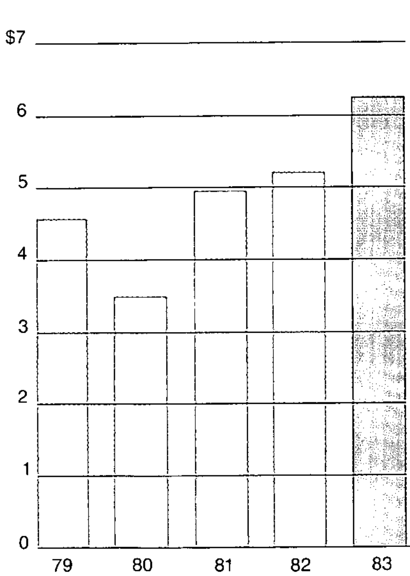
Biomass

In 1983, Edison received the Edison Electric Institute's highest award, the Edison Award, for the Company's commitment and success in developing renewable and alternative resources, for improving its financial strength through an innovative financing and resource strategy, and for implementing effective cost controls, while, at the same time, providing a fair return to shareholders, and high quality service at reasonable cost to customers. That commitment is designed to stand the test of a changing decade and allow an innovative transition from old to new ways of electric generation. Today, Edison uses nine primary resources to generate electricity—water, oil, gas, nuclear, coal, geothermal, wind, solar and biomass—more resources than any other electric utility in the world.

Contents

1983 Annual Report

Highlights	1983	1982	% Change	% Five-Year Compound Growth
Operating Revenues (000)	**$4,464,256**	$4,302,602	3.8%	13.9%
Fuel and Purchased Power Costs (000)	**$2,027,756**	$2,227,901	(9.0)	11.0
Earnings Available for Common and Original Preferred Stock (000)	**$617,303**	$483,358	27.7	25.0
Weighted Average Shares of Common and Original Preferred Stock (000)	**99,174**	94,257	5.2	11.5
Earnings Per Share	**$6.22**	$5.13	21.2	12.1
Dividends Paid Per Common Share	**$3.59**	$3.31	8.5	9.9
Total Assets (000)	**$11,035,060**	$10,157,564	8.6	12.8
Construction Expenditures (000)	**$805,497**	$993,903	(19.0)	7.2
Kilowatt-Hour Sales (000)	**59,892,638**	59,326,853	1.0	1.0
Number of Customers	**3,325,303**	3,275,144	1.5	2.2
Number of Employees	**16,292**	15,797	3.1	4.9
Area Generating Capacity at Peak (Megawatts)	**16,365**	15,349	6.6	1.8

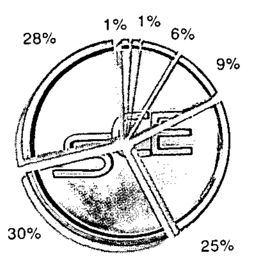


Earnings Per Share of Common Stock

The Company's 1983 earnings per share of $6.22 were the highest in the Company's history, surpassing by 21% the previous high recorded in 1982. This increase primarily reflects higher non-cash allowances for funds used during construction, continuing emphasis on productivity and cost controls, and the general rate increase effective January 1, 1983.

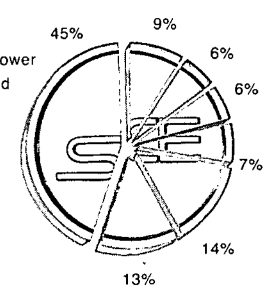
Sources

- 30% Commercial
- 28% Residential
- 25% Industrial
- 9% Public Authorities
- 6% Resale
- 1% Agricultural
- 1% Other



Distribution

- 45% Fuel and Purchased Power
- 14% Dividends and Interest
- 13% Operation
- 9% Taxes and Other
- 7% Depreciation
- 6% Maintenance
- 6% Reinvested Earnings



Sources and Distribution of Revenues

The Company's sources of revenues in 1983 reflected a well-balanced contribution from each of the major customer classes. Fuel costs were lower than those in 1982, but they continued to represent a major portion of the distribution of revenues.

To Our More Than 190,000 Shareholders:

Your Company had an exceptionally successful year in 1983. For the third time in our history, we earned the Edison Electric Institute's highest honor, the Edison Award, as the outstanding Company among the nation's nearly 200 investor-owned electric utilities.

The award was based on your Company's commitment and success in developing renewable and alternative resources, for improving its financial strength through an innovative financing and resource strategy, and for implementing effective cost controls, while, at the same time, providing a fair return to you, our shareholders, and high quality service at reasonable cost to our customers.

The continued hard work, innovation, productivity, cost consciousness and responsiveness to customer needs by our officers, managers and employees resulted in a number of financial and operating accomplishments for 1983.

- Earnings increased to a record level for the third consecutive year, reaching $6.22 per share, up 21% over 1982 earnings of $5.13 per share.
- For the third consecutive year, we essentially achieved our rate of return on common equity authorized by the California Public Utilities Commission (CPUC).
- The dividend on our common stock was raised on an annual basis to $3.80 per share from $3.52 per share a year ago. We implemented an aggressive dividend policy in 1977 and, since then, have increased the dividend at least once per year. For the past five years, dividends paid per share have increased an average of 9.9%.
- The market price of our common stock exceeded book value throughout most of the year, reaching $42¾ per share on November 2, or just 12 cents per share below its all-time high in 1965. During 1983, our common stock provided a total return of 23%, comprised of price appreciation and dividends paid.
- The Board of Directors, on January 19, 1984, approved a two-for-one split of the Company's common stock to price it at a more attractive level. The split is scheduled to become effective July 5, 1984, subject to shareholder approval at the annual meeting on April 19.
- San Onofre Nuclear Unit 2 completed full-power testing in August and began commercial operation the same month. An initial portion of the Unit's revenue requirements was included in rates in October, with a subsequent increase authorized in November. The remainder is accruing in a balancing account.
- San Onofre Nuclear Unit 3 received its full-power license from the Nuclear Regulatory Commission (NRC) in September and is undergoing full-power testing. We expect to complete the warranty run and, subject to CPUC approval, place the unit into rates in mid-1984.
- Employee awareness of, and responsiveness to, the needs and concerns of our customers were given increased attention and emphasis at all levels of our organization. Additional funds, equipment and personnel were allocated to meet this objective, including additions to data processing and customer information system facilities, and greater attention to the selection and training of customer service representatives.
- Alternative and renewable resources, scheduled to provide 2,190 megawatts (MW) of electricity to the Edison system by 1993, are progressing ahead of schedule. Since the inception of our accelerated program in 1980, 1,400 MW of alternative and renewable resources are either on line, under construction or represented by signed contracts or letters of intent.
- Fuel and purchased power costs, the largest single component of the total cost of providing electricity to customers, decreased for the second consecutive year to $2 billion in 1983, compared to $2.2 billion in 1982 and an all-time high of $2.6 billion in 1981. The decline is primarily attributable to record supplies of hydroelectric power, record economy power purchases from other utilities and decreases in the price of natural gas.
- Low-cost purchased power reached a record 37% of the Company's total kilowatt-hour (KWH) requirements. This saved customers approximately $900 million in fuel costs during the year, or the energy equivalent of 41 million barrels of fuel oil or natural gas.

- Purchased power and natural gas availability resulted in no fuel oil being purchased by Edison in 1983 for the first time in more than 40 years.
- Electric rates for the average-usage Edison residential customer were 10% less in January 1984 than in January 1982 as a result of lower fuel costs and effective productivity and cost control programs.
- Conservation programs, with effective support by customers, saved more than $280 million in fuel costs in 1983 by reducing electrical usage by 5.6 billion KWH, the energy equivalent of about nine million barrels of costly oil or natural gas.
- Load management programs through 1983 resulted in a reduction in our peak demand of 520 MW. This reduces financing requirements and eliminates the need to build approximately $250 million of new generating capacity.

Our record earnings reflect the favorable impact of the 1983 general rate increase, continued stringent cost control and productivity improvement programs, and an approximately 20% increase over 1982 in non-cash allowances for funds used during construction. With the transition of San Onofre Units 2 and 3 from construction into commercial operation, and related rate actions by the CPUC, the cash portion, and therefore the quality, of our earnings will improve.

During 1983, the CPUC granted, in two steps, $305 million of revenues related to the operation of San Onofre Unit 2. An application is pending before the CPUC covering the $136 million difference between the $305 million currently authorized and $441 million, which is the currently projected 1984 annual cost of owning and operating Unit 2. The CPUC authorized the establishment of an interest bearing balancing account to accumulate the remaining investment-related revenue requirements for Unit 2, and a further decision on these deferred amounts is expected by mid-year. The total increase is being partially offset by nuclear fuel savings, in lieu of burning oil and natural gas.

In October, the Company filed an application with the CPUC for $454 million annually to cover capital and operating costs associated with San Onofre Unit 3. This increase also will be partially offset by nuclear fuel savings, and a decision is expected mid-year.

On a combined basis, Units 2 and 3 represent a total annual rate increase of $895 million, to be partially offset by an estimated $390 million of fuel savings, resulting in a net revenue increase of about $500 million, or approximately 11% of 1983 revenues.

In a separate proceeding, the CPUC, with an independent consultant, also is reviewing the costs of San Onofre Units 2 and 3 and a decision on this matter is expected by year-end.

At the time of construction in 1974, it was estimated that San Onofre Units 2 and 3 would cost $1.6 billion. These costs have increased to $4.5 billion. Nevertheless, the construction cost increase for these units is among the lowest increase for any nuclear plant built in the United States during this period.

Contributing to the increased costs of San Onofre Units 2 and 3 were the impact of double-digit inflation and record interest rates experienced worldwide during the past 10 years, increased labor and material costs, and cost increases associated with changes in design criteria, and significant delays caused by extended regulatory reviews and regulatory policy changes following the Three Mile Island accident.

Your management believes that the costs are prudent and justified, and compare favorably with other nuclear projects or any other complex, long-lead-time project.

San Onofre Unit 1 was taken out of service in April 1980 for maintenance and sleeving repairs to steam generator tubes, and again in February 1982 for NRC-required backfits, fire protection modifications and seismic upgrading. The unit has remained out of service as efforts continue between Edison and the NRC to define the scope of backfitting measures, including seismic, and the scheduling of work. Although this backfitting program involves substantial expenditures, we are encouraged by recent progress. Further review is continuing between Edison, the NRC and the CPUC.

Notwithstanding recent outages, Unit 1, since beginning operation in 1968 to February 1982, attained an average lifetime capacity factor of 66%, 9% higher than the national average for nuclear plants, saving customers about $450 million in more expensive replacement fuel.

Edison also has a 15.8% ownership interest in three 1,222-MW units being constructed at the Palo Verde Nuclear Generating Station near Phoenix, Arizona. This project, being managed by Arizona Public Service Company, is experiencing some startup delays and upward cost revisions.

With the completion and inclusion in rates of the San Onofre and Palo Verde nuclear units, and the continued development of renewable and alternative resources, construction expenditures, financing requirements and the need for costly fuel oil and natural gas should decrease in the future.

Construction expenditures for the next five years are projected to decrease approximately $200 million from the previous five-year period, from $4.2 billion in 1979–83 to $4 billion in 1984–88. On a constant dollar basis, using 1984 dollars, the 1984–88 projection totals $3.4 billion. Electric generation from fuel oil and natural gas is projected to decrease to 22% by 1993, compared with 32% in 1983 and 66% in 1973.

In December 1983, we filed with the CPUC for a general rate increase of $453 million annually, or 8.3%, to be effective January 1, 1985, covering projected 1985 cost increases for capital and operating expenditures, other than for fuel, and the continued need for a competitive investment return for shareholders. We are seeking an increase in the rate of return on common equity from the 16% currently authorized to 17.5%.

On January 1, 1984, as part of the 1983 general rate case decision authorizing an interim rate increase, the CPUC reviewed and authorized a $96.4 million rate increase to help offset increases of certain non-fuel-related costs experienced between general rate cases.

Edison now provides electric service to more than nine million people through over 3.3 million meter connections. At a projected 1.7% compound annual growth rate, our customers are expected to number nearly four million by the end of 1993. Our 10-year forecast projects KWH consumption to increase at a 1.6% compound annual growth rate, from 59.9 billion KWH in 1983 to nearly 72 billion KWH in 1993.

Success in our load management programs has reduced our projected peak demand growth rate through 1993 from 2.4% to 2% annually, requiring just over 5,000 MW of new generating capacity, and enabling the Company to eliminate the need for a 1,500-MW coal-fired generating plant at an estimated cost savings of $1 billion.

All of our additional generating capacity requirements through 1993, other than from the Company's 200-MW Balsam Meadow hydro project at Big Creek, power purchases and nuclear plants currently under construction, is scheduled to be met by Company and third-party-owned renewable and alternative resources, including cogeneration, small hydro, wind, geothermal, solar, synthetic fuel (coal gas), biomass and fuel cells.

Throughout the year, a number of significant executive changes were made to further strengthen the management of your Company, including the election of a new director and officers.

Carl F. Huntsinger, president and chief executive officer of Blue Goose Growers, Inc., an affiliate of Sunkist Growers, Inc., was elected to the Company's board of directors.

Two directors retired from the Board in 1983—John V. Newman, after 26 years of dedicated service, and Richard R. Von Hagen, following over 13 years of valued service.

P. L. Martin, formerly vice president, customer service and conservation, was elected senior vice president with responsibility for customer service, human resources, conservation and corporate communications. L. T. Papay, formerly vice president, advanced engineering, was elected senior vice president with responsibility for advanced engineering, power supply and system development.

Charles B. McCarthy, Jr., formerly manager of fuel supply, was elected vice president, advanced engineering. Kenneth P. Baskin, formerly manager of nuclear engineering, was elected vice president, nuclear engineering, safety and licensing, and Harold B. Ray, formerly site manager of the San Onofre Nuclear Generating Station, was elected vice president and site manager, San Onofre Nuclear Generating Station.

Effective January 1, 1984, Richard K. Bushey, formerly assistant controller, was elected vice president and controller, succeeding A. L. Maxwell, who retired after nearly 35 years of dedicated service.

Effective February 1, 1984, John E. Bryson, partner in the law firm of Morrison and Foerster, and former president of the California Public Utilities Commission, was elected senior vice president, with responsibility for the law, controller's, treasurer's and secretary's departments, and Michael R. Peevey, formerly president of the California Council for Environmental and Economic Balance, was elected vice president, governmental affairs and revenue requirements.

In the face of the most difficult nuclear licensing and construction period in the history of our nation, which is threatening the financial integrity of many utilities completing nuclear facilities, your Company experienced a successful year and strengthened its ability to meet its public service responsibility to customers and its financial stewardship to shareholders.

Fair and responsible regulation at the federal and state levels measureably added to the constructive and cooperative environment that underscored our many successes in 1983. With the continued policy guidance and counsel of our directors, the dedication and overall fine performance of our officers, managers and employees, and the continued support of you, our shareholders, we view the future with confidence and optimism.

Howard P. Allen
President

William R. Gould
Chairman of the Board and
Chief Executive Officer

February 16, 1984

Our Employees and Customers

The accomplishments of 1983 reflect the hard work, dedication and innovation of more than 16,000 Edison employees.

Edison employees did an outstanding job maintaining the Company's financial integrity, strengthening its nuclear operations, engineering new advances in electric generation and distribution, increasing coal and steam plant productivity, and achieving cost savings in resource management through off-system purchases, conservation and load management.

Special efforts were made to further improve the Company's ability to respond promptly and effectively to customer needs. Throughout the year, senior management met personally with public contact employees to reaffirm the importance of high quality customer service as a top corporate priority.

Edison energy audits for residential, commercial, industrial, agricultural and public authority customers achieved a total savings of almost 1.6 billion kilowatt-hours in 1983, and a demand reduction of 335 megawatts.

To this end, the Company in 1983 added personnel, intensified training, further decentralized division reporting authority to bring decisions closer to the customer, and upgraded other facets of customer service functions.

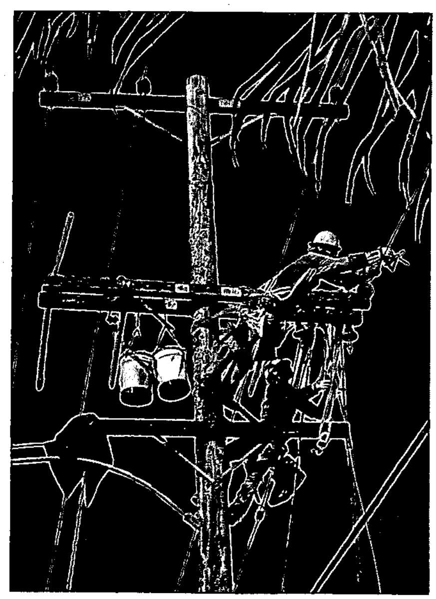
During the year, nearly 800 Edison customer service representatives handled about four million telephone calls and an equal number of customer visits at 76 local offices. In addition, more than two million service requests were handled by field service personnel.

A 24-hour toll-free telephone line aided customers with speech and hearing impairment, and a winter energy assistance program was established for low-income residential customers. Training of customer service representatives was intensified in all areas of customer contact and communications, and the Company continued to improve its computerized Customer Information System facilities.

Edison's 545 meter readers each read an average of 380 electric meters daily in 1983, a high standard of performance per reader.

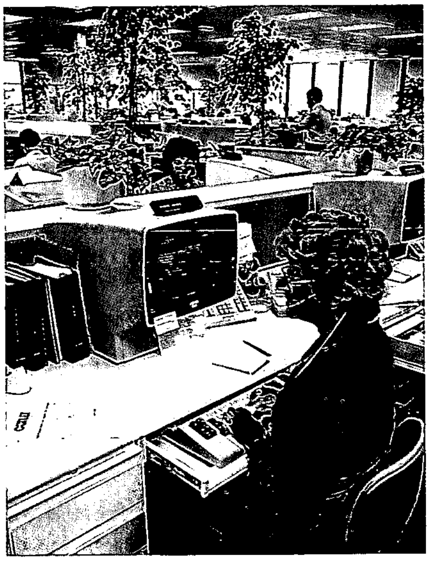
The number of informal complaints to the California Public Utilities Commission (CPUC) decreased in 1983 by 38% to 1,006. In addition, the number of billing inquiries reflecting customer concern over the cost of electricity decreased by 22% to 70,000.

In its 50,000 square-mile service territory encompassing more than 9 million people, Edison served 3.3 million customers in 1983, including



Edison employees worked approximately 250,000 overtime hours to restore service and repair facilities for nearly one million customers during the most devastating wind and rain storms in the Company's history in late 1982 and early 1983.

50,159 new customers. In serving these customers, Edison construction crews replaced more than 6,000 poles, inspected more than 13,000 underground vaults and maintained over 80,000 miles of overhead and underground lines in 1983. The Company's 545 meter readers each read an average of 380 electric meters daily, a high standard of performance per reader. Working with enforcement agencies, field service personnel identified and halted the theft of more than four million kilowatt-hours (KWH) of electricity through an intensified Energy Theft Prevention Program.



Edison's 800 customer service representatives responded to about four million phone calls and an equal number of customer visits at the Company's 76 local offices in 1983.

The most devastating wind and rain storms in the Company's history in late 1982 and early 1983 caused Company employees to work approximately 250,000 overtime hours to restore service and repair facilities for nearly one million customers, at a cost of more than $20 million. Customer service representatives handled more than 185,000 calls in connection with the outages from 23 separate storms.

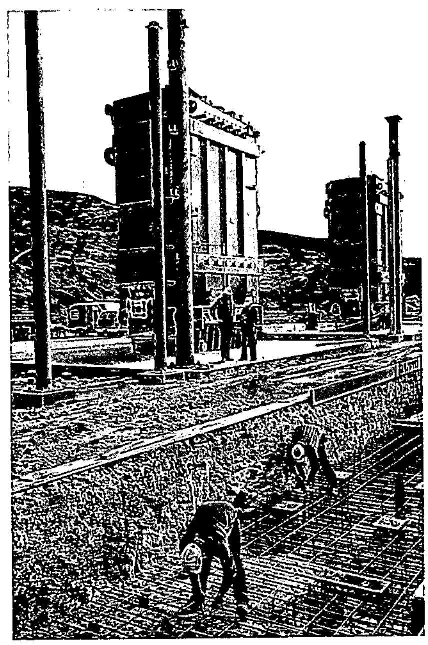
In late January 1984, storm damage from hurricane-force winds caused Edison crews to work more than 97,000 hours restoring service to more than 843,000 customers and repairing damage to facilities, at a cost of more than $6.6 million.

In addition to service on the job, the Company encourages its employees to participate in community affairs. As responsible community members, employees provided leadership and participated in youth league sports, Special Olympics, Junior Achievement, scouting, and YMCA and YWCA activities. Employees were also involved in senior citizen programs, cultural activities, church organizations, and groups that render voluntary assistance in areas such as low-income housing and unemployment.

Edison employees personally gave more than $2 million in 1983 to United Way programs. This donation assisted more than 200 local agencies and made Edison people among the leading contributors, on a per capita basis, to charitable organizations in California.

Employees who have acted with exceptional courage and initiative in emergencies, or who have performed humanitarian acts of service have been formally recognized by the Company since 1980. To date, 67 employees have received the Jack K. Horton Humanitarian Awards, named in honor of the contributions and dedicated service of the Company's former Chairman. These employees pulled persons from burning houses and burning or submerged cars, rescued children from attacking dogs, gave first-aid to accident victims, saved choking and drowning victims, and administered cardiopulmonary resuscitation.

The 78-year-old Edison motto, "Good Service, Square Dealing and Courteous Treatment," continues to serve as the guiding operating principle for the Company in its relationship with its employees, customers and the communities it serves.



Edison's Serrano Substation, scheduled for completion in late 1984, will primarily step-down high voltage electricity from Arizona's Palo Verde Nuclear Generating Station for the benefit of Edison customers.

Year in Review

Nuclear Generation

Because of the Company's substantial nuclear investment and in light of intense regulatory and public scrutiny of nuclear operations throughout the nation, Edison moved to strengthen and centralize its nuclear organization in 1983. As outlined in the Letter to Shareholders, two company officers were given direct authority for nuclear operations, one at the site of the San Onofre Nuclear Generating Station and the other responsible for nuclear engineering, safety and licensing.

This nuclear organization, including its technical, engineering and support personnel, was responsible for successfully bringing the 1,100-megawatt (MW) San Onofre Unit 2 through full-power testing and into commercial operation in August 1983. An initial portion of the unit's revenue requirements was included in rates in October, with a subsequent increase authorized in November. The remainder is accruing in a balancing account.

San Onofre Nuclear Unit 3 received its full-power license from the Nuclear Regulatory Commission (NRC) in September 1983 and is undergoing full-power testing. The Company expects to complete the warranty run and, subject to CPUC approval, place the 1,100-MW unit in rates in mid-year.

During the past decade, changes in regulatory requirements have resulted in substantial modifications to original nuclear plant design. As a result, San Onofre Unit 1, which was originally placed in service in 1968, was taken out of service in February 1982 for NRC-required backfits, fire protection modifications and seismic upgrading.

Unit 1 has remained out of service as efforts continue between Edison and the NRC to define the scope of all necessary backfitting measures, and the scheduling of work. Although this program involves substantial expenditures, the Company is encouraged by recent progress. Further review is continuing between Edison, the NRC and the CPUC.

Edison has an 80% ownership interest in San Onofre Unit 1 and a 75% ownership interest in San Onofre Units 2 and 3. The Company is responsible for the management and operation of the three units, and has a total megawatt ownership in the units of 2,010 MW.

Edison also has a 15.8% ownership interest in three 1,222-MW units being constructed at the Palo Verde Nuclear Generating Station near Phoenix, Arizona. This project, being managed by Arizona Public Service Company, is experiencing some startup delays and upward cost revisions.

Alternative and Renewable Resources

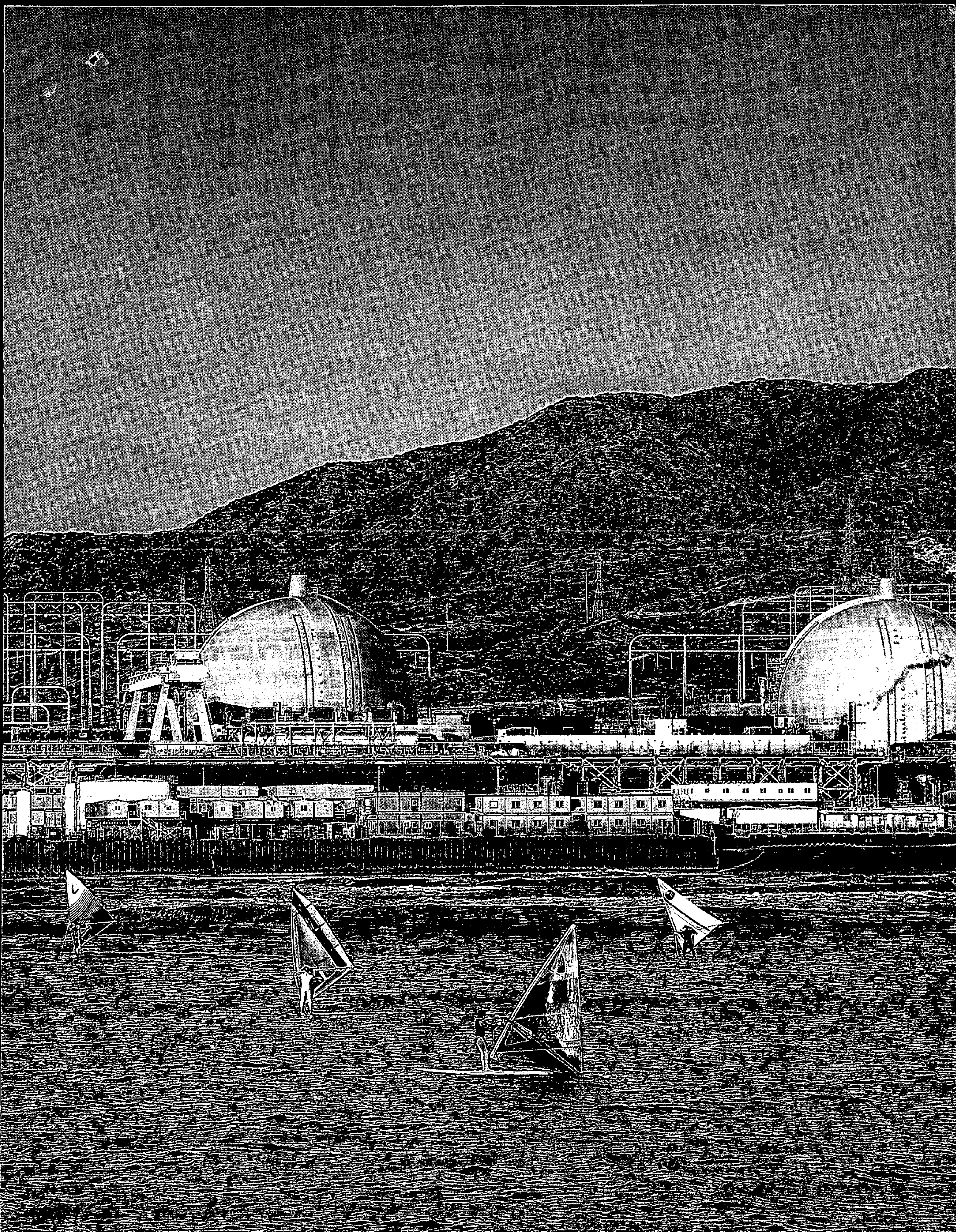
Edison continues to be ahead of schedule in its plan to bring 2,190 MW of renewable and alternative energy sources into production by 1993. The Company now obtains electric power from nine primary energy resources—water, oil, gas, nuclear, coal, geothermal, wind, solar and biomass—more resources than any other electric utility in the world.

Since the Company's accelerated development program began in 1980, more than 1,400 MW of alternative and renewable resources are either on line, under construction or represented by signed contracts or letters of intent. At year-end, alternative and renewable resources developed by third-party entrepreneurs contributed more than 155 MW of capacity to the Edison system at a capital savings over traditional central station generation of more than $75 million.

Alternative and renewable power generation technologies include:

Wind—At the end of 1983, nearly 1,400 wind turbines of various designs were installed and producing up to 70 MW of power. A total of 15 wind parks were in initial stages of operation in the Tehachapi Mountain and San Gorgonio Pass Wind Resource Areas. Edison, through purchase contracts, has received more than 15 million KWH of energy from these third-party projects.

NUCLEAR POWER: Located on the Pacific shore near San Clemente, California, the three unit, 2,650-megawatt San Onofre Nuclear Generating Station at full operation will displace the energy equivalent of about 25 million barrels of oil and gas annually. In 1983, Unit 2 was placed in full-power operation and a full-power operating license was approved for Unit 3.



Solar—Edison is involved in five solar technologies utilizing the sun's renewable energy, either for direct conversion to electricity, or for concentrating it into usable heat energy:

- Central Receiver: The 10-MW Solar One generating station, located at Edison's Cool Water Generating facility, near Daggett, California, began power production in April 1982 and set a single-day energy production record in 1983 of 104,000 KWH.
- Photovoltaic: ARCO Solar Industries' 1-MW plant near Hesperia, California, has generated more than 2 million KWH of electricity since connection to Edison's grid in November 1982.
- Parabolic Dish: Advanco's 25-KW system, under construction near Rancho Mirage, California, is the first of a family of parabolic dish reflectors that are scheduled to be built in the current decade.
- Solar Trough: Operation of the first phase of the Luz parabolic trough 43-MW Solar Energy Generating Station is scheduled to begin in the current year in the Mojave Desert near Daggett, California.
- Solar Pond: Agreements were signed in late 1983 between Edison and Ormat Turbines, Ltd., for a 48-MW solar pond system to be installed at Danby Dry Lake in the Mojave Desert east of Twentynine Palms, California.

Biomass—Waste-to-energy power production currently is a small but promising contributor to the Edison power grid. Applications to generate electricity range from landfill gas recovery and digester gas from sewage treatment facilities to wood-waste combustion, used tire combustion, agricultural waste and municipal refuse.

Commitments have been made by independent developers for 28 biomass projects involving 262 MW. Eleven projects totaling 27 MW currently are in operation.

Edison also is operating a prototype project at its Highgrove Generating Station to convert wood waste into a clean, combustible gas fuel. This project uses the nation's largest down-draft wood gasifier.

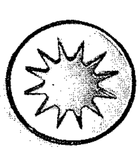
Cogeneration—Cogeneration facilities produce electricity and thermal energy from a single fuel, an ideal conservation measure. Heat processes in industries such as paper manufacturing, milk processing, oil recovery and refining, cement and chemical production frequently use large volumes of steam, and it is often feasible to cogenerate electric power with the same fuel used in these processes.

Commitments with developers total 527 MW in 35 different projects. Already operational are 27 projects with over 220 MW of capacity.

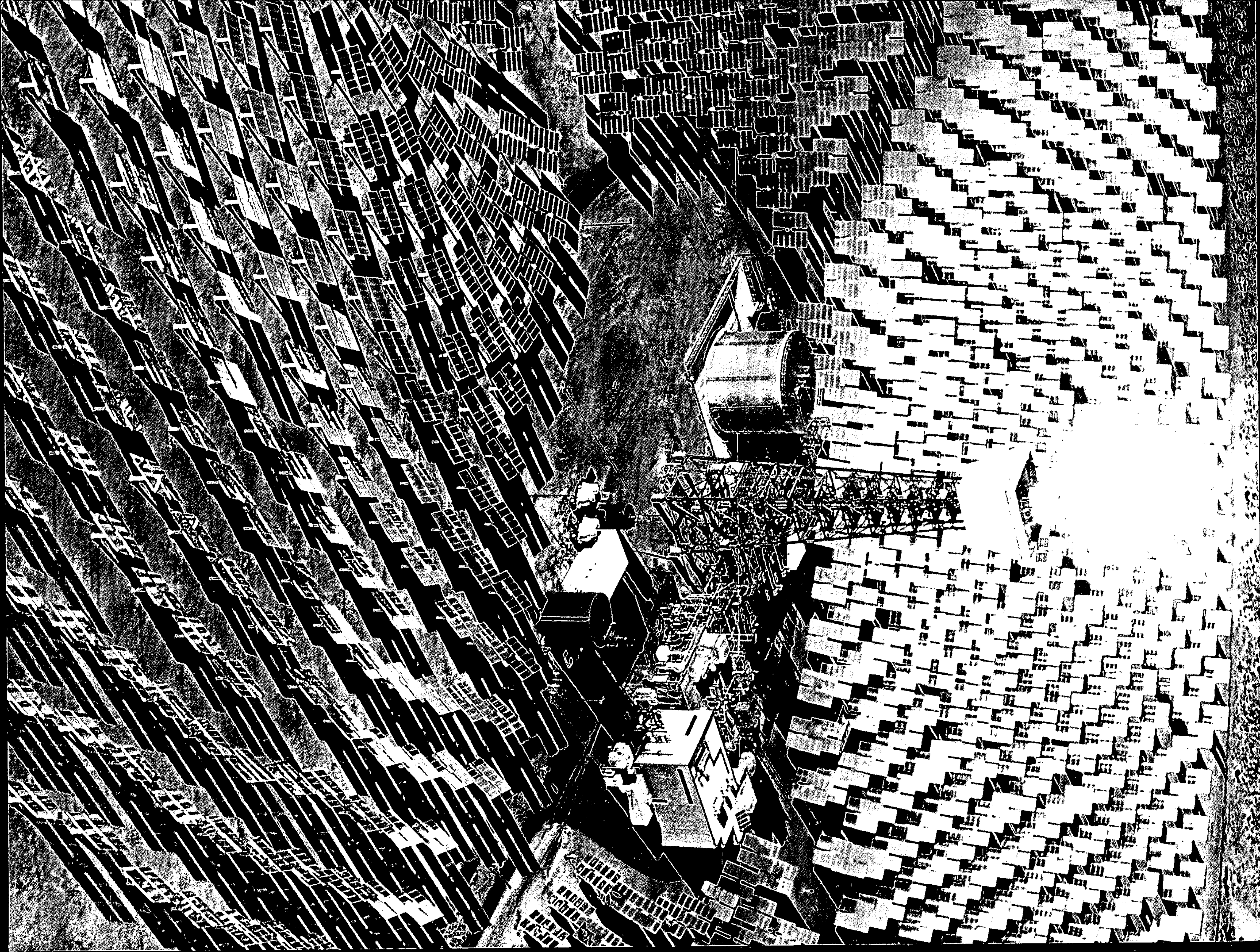
One of the largest cogeneration projects in the nation, the Kern River Oil Field Cogeneration Project in the San Joaquin Valley, received approval from the California Energy Commission in 1983 and is scheduled for initial operation in late 1985. The project is a joint venture between subsidiaries of Edison and the Getty Oil Company. The project will generate up to 300 MW of electricity for Edison customers and for oil field operations while utilizing waste heat to produce steam for oil recovery.

Geothermal Power—The generation of electricity utilizing hot water and steam resources located beneath the earth's surface produced 95 million KWH in 1983 from two pilot plants in California's Imperial Valley. The 10-MW plants at Brawley and the Salton Sea continued to advance the technology needed to utilize the salty, corrosive hot water resources prevalent in the area.

Commitments have also been made to obtain power from three independent geothermal projects totaling 62 MW. In addition, Edison will begin receiving in the current year the first portion of a 70-MW power purchase from Mexico's Cerro Prieto geothermal generating station.



SOLAR POWER: Solar rays reflect off 300-foot high central receiver tower of Solar One, the world's largest solar thermal generating station near Daggett, California. In successful operation for the past year, the station produces 10 megawatts of electrical energy using 1,818 heliostats, or mirrors, that concentrate solar rays on tower coolant to create turbine steam.



Research and Development

Edison's developmental efforts in alternative and renewable resources began in 1972, and are a direct extension of a commitment to utilize promising new technology to benefit shareholders and customers that began with the Company's pioneering development of the first long-distance alternating current transmission line in the 1890s.

The Cool Water Coal Gasification Program is representative of Edison's efforts to move promising alternative technologies into commercial electric production. The project, which has received U.S. Synthetic Fuel Corporation's price support for its operational phase, will convert 1,000 tons of coal per day into a clean-burning gas to power a 100-MW generating facility.

Edison's Wind Energy Center near Palm Springs also continues to lead as a focal point for utility wind energy research in the United States. In 1983, the world's largest Darrieus vertical axis wind turbine generator (WTG) was erected and began start-up testing; testing also began on a 100-KW Wenco horizontal axis unit; and testing continued on the three-bladed, Bendix horizontal WTG.

Research and development in ecological and environmental systems was intensified in 1983. Testing continued on a 90%-efficient, 107-MW catalytic NOx removal system, the largest of its type in the nation. As part of ongoing acid rain and fog studies, the Company joined with the Coordinating Research Council in support of the standardization of collection and evaluation methods for these phenomena in Southern California and the Northeast.

Edison was recognized by the California Department of Fish and Game in 1983 for innovative and aggressive marine resource management programs, including SCE's support of the Pendleton Artificial Reef Project, the largest ecosystem of its type in the U.S.

Edison Hydro

More than 1,300 MW of hydroelectric capacity is currently on line from Edison's 21 federally licensed hydro projects and from Edison's Hoover Dam entitlement.

With a capacity of 776 MW, the Big Creek hydroelectric complex in the Sierra Nevadas is the mainstay of the Edison hydro system. It has the hardest working water in the world, irrigating central California's San Joaquin Valley from six dams, eight tunnels and eight powerhouses built over a period of 70 years. Further extending Big Creek's capability, construction began in 1983 on the 200-MW Balsam Meadow hydro project, which will become the Company's largest hydro plant. Scheduled for completion in 1987, Balsam Meadow will feature an underground hydro powerhouse to utilize water flowing from Huntington Lake to Shaver Lake.

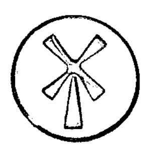
New Allocation of Hoover Dam Power

In 1930, Edison and other utilities contracted to purchase power from Hoover Dam in future years, and such funding permitted the construction of this multi-purpose project. These contracts expire in 1987. However, in 1983 the Department of Energy proposed new allocations for Hoover power for Edison, which, although somewhat reduced, would still provide Edison customers 30 more years of low-cost hydro power. The contracts are subject to federal legislative approval, which is expected in the current year.

Hydro Project Relicensing

Until recently, it was generally agreed that the Federal Power Act of 1920 gave preference to states and municipalities for the original issuance of licenses for new hydroelectric projects on federal lands, but preference to public agencies did not apply to the relicensing of existing projects. Congress, when reviewing the law in 1968, was so advised of this view by the Chairman and General Counsel of the Federal Power Commission, which has since become the Federal Energy Regulatory Commission (FERC).

Then, in 1980, FERC, which is responsible for issuing hydroelectric project licenses, issued a declaratory order stating that municipalities do have preference over investor-owned utilities in relicensing. The appellate courts let this decision stand.



WIND POWER: Ranchers and energy entrepreneurs now share Southern California's Tehachapi Mountain Range where small wind turbine arrays, along with other renewable and alternative energy resources, will reduce fuel oil and gas dependence and the need to build large, capital-intensive generating plants.

This new interpretation would deprive electric customers of investor-owned electric utilities whose projects are up for relicensing of the benefits of low-cost hydro power and unfairly give these low-cost benefits to the customers of municipal utilities.

In 1983, FERC rendered its first decision after hearings in a contested proceeding. It ruled that municipalities do not have preference in relicensing. This decision is now being appealed by the municipalities.

Because of the two conflicting FERC rulings and subsequent court appeals, legislation was introduced in the Congress in 1983 to prevent the benefits of low-cost hydroelectric power from being taken from customers of an existing licensee and given to the customers of a municipality who did not pay for the existing project. Action on this measure is expected this year.

This issue is important to Edison customers because municipalities claiming preferred status have already filed competing applications for 11 hydro projects in the United States, including Edison's Rush Creek and Lee Vining Creek Projects in the Sierras near Bishop. Edison has four other hydro projects subject to relicensing by 1993.

Edison's customers' rates will increase unnecessarily and unjustifiably if these hydro facilities are taken away since Edison would have to purchase or produce more costly replacement power. In California, fuel costs, including the benefits of low-cost hydroelectric power, are fully and promptly passed on to the electric customer.

Edison's efforts to retain the benefits of low-cost hydroelectric power for its customers have received strong support from customers, shareholders, legislators, regulators, local government and public opinion leaders. Over 100 cities, 12 counties and more than 15,000 customers have sent letters, petitions, and resolutions to FERC in support of retaining the benefits from these hydroelectric projects.

The investor-owned electric utility industry has undertaken major efforts to provide full information to its customers about the potential cost increase to them and is supporting legislation to protect their interests.

Major Litigation

In recent years, Edison has experienced increased antitrust and contract litigation involving claims for significant damages, resulting in related increased legal fees, manpower requirements and expenses.

Antitrust litigation initiated by some of Edison's municipal resale customers, and litigation involving the Company's fuel oil procurement contract with Chevron are requiring substantial legal effort and expense. These matters are discussed in more detail in Note 2 of Notes to Financial Statements. Also, Edison is engaged in a lawsuit against Westinghouse relative to equipment warranties.

Fuel and Purchased Power

Until the 1960s, Edison generated electric power primarily on its own system to provide low-cost electricity to customers in a reliable manner. But as a result of increased emphasis on air pollution control in the late 1960s and skyrocketing fuel oil costs following the OPEC oil embargo, Edison began increasing its purchases of off-system power from other suppliers to keep customer electric costs down and to diversify its fuel mix and minimize emissions.

This quest for low-cost power led to Edison's participation in the late 1960s in the construction of the Pacific Intertie transmission system to the Pacific Northwest to import low-cost surplus hydro power for its customers. The Company also participated in the construction of Units 4 and 5 at the Four Corners coal plant in New Mexico in 1969 and the Mohave coal plant in Nevada in 1971. Extra high voltage lines were constructed to import Edison's share of power from Four Corners and Mohave to Southern California.

BIOMASS POWER: Wood, which once supplied 90% of America's energy needs, is experiencing a rebirth as an electric energy producer in a demonstration project at Edison's Highgrove Generating Station near Riverside, California. The project uses the nation's largest down-draft wood gasifier.

These lines also enable the Company to purchase surplus power, primarily generated from coal, from Southwest utilities. As a result, off-system power purchases, primarily from the Pacific Northwest and Southwest, have dramatically increased over the past 16 years, climbing from one percent of total KWH requirements in 1967 to a record 37% in 1983, or approximately 25 billion KWH. The majority of these off-system purchases are interruptible and do not eliminate the necessity to utilize company-owned facilities to meet system peak demand.

Power purchases saved Edison customers approximately $900 million in 1983 by displacing the energy equivalent of 41 million barrels of more costly fuel oil or natural gas. In addition, the Company burned the lowest annual amount of fuel oil to generate electricity since 1950 with 3.4 million barrels used from storage. As a result, no fuel oil was purchased in 1983 for the first time in more than 40 years.

Natural gas consumption also decreased from 257 billion cubic feet in 1982 to 215 billion cubic feet in 1983, or the equivalent of 37 million barrels of fuel oil. In 1983, natural gas represented 29.5% of the Company's fuel mix compared to 37% a year ago.

Even though KWH generation increased in 1983, combined fuel and purchased power costs declined by 9% to $2 billion, compared to $2.2 billion in 1982 and an all-time high of $2.6 billion in 1981. This decline is attributable primarily to record supplies of hydroelectric power, record economy power purchases from other utilities and decreases in the price of natural gas. Nevertheless, fuel and purchased power costs continue to be the single largest component of the total cost of providing electric service to customers, representing 45 cents out of each 1983 revenue dollar, down from 52 cents in 1982 and the record high of 63 cents in 1981.

To continue to expand the Company's off-system power purchase capability in the years ahead, Edison has applied to the CPUC for approval to extend a 500-kilovolt transmission line into the Company's system from the Palo Verde Nuclear Generating Station in Arizona. Edison and the Los Angeles Department of Water and Power also are studying the feasibility of upgrading the Pacific Intertie 846-mile DC line from 2,100 MW to 3,100 MW by 1988 to allow power purchase increases from the Pacific Northwest of up to two billion KWH annually.

Annual Peak Demand

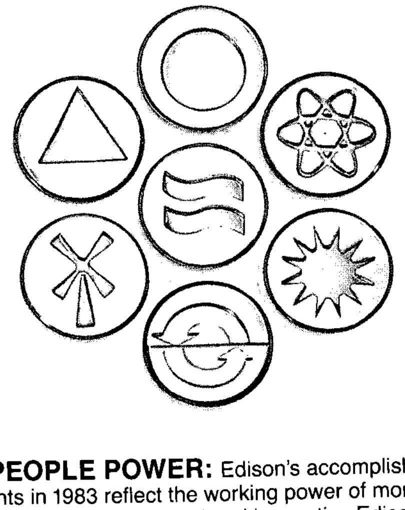
The Company recorded a 1983 area peak demand of 13,464 MW on September 12, a 2.4% increase over the peak demand of 13,149 MW recorded on September 2, 1982, but still below the record peak of 13,738 MW reached during unusually hot weather in 1981. The annual compound growth in peak demand over the last five years has been 2.1%.

Energy Sales

Total energy sales to Edison's 3.3 million customers in 1983 were 59.9 billion KWH, a 1% increase over sales of 59.3 billion KWH in 1982, but below the record of 62.5 billion KWH set in 1981.

Energy sales were reduced by over one billion KWH in 1983 through the expiration on April 3, 1983, of a 20-year energy sale agreement with the California Department of Water Resources (CDWR) for California Aqueduct project pumping. This reduction was more than offset by residential and commercial energy sales growth. Edison is continuing to cooperate with CDWR on water project electric use under a new energy exchange arrangement.

Energy sales to six resale cities declined 4.1% in 1983 as some cities began receiving energy through their ownership in San Onofre Unit 2 and because of increased power purchases from outside Edison's system.



PEOPLE POWER: Edison's accomplishments in 1983 reflect the working power of more than 16,000 dedicated and innovative Edison people. As responsible members of the communities in which they live and work, Edison people make it happen, strengthening the Company's service to both customers and shareholders.

Total electric consumption by Edison's 2.9 million residential customers in 1983 increased by 4.7% to 17.2 billion KWH from 16.4 billion KWH in 1982, primarily as a result of the improved economy, warmer summer temperatures and the addition of 42,556 new residential customers to the Company's service territory during the year. The annual compound growth in residential KWH sales over the last five years has been 2.2%.

Industrial KWH sales, which have declined annually since 1981, recovered by year-end 1983 to within 0.2% of their 1982 sales level, even though the Company lost five major industrial customers. In contrast, commercial KWH sales increased by 7.8% over 1982, growing for the past five years at an average annual rate of 3.8%.

Sales to agricultural customers in 1983 dropped 17.3% to 709 million KWH from 857 million KWH in 1982. Primarily because of record rainfall and hydro runoff that reduced the need for deep-well pumping, the 1983 agricultural sales level was the lowest recorded since 1946.

Conservation and Load Management

In 1983, the combination of customer response to Edison's conservation programs, plus the Company's direct conservation efforts on its system, achieved a savings of approximately 5.6 billion KWH, resulting in a fuel cost savings of more than $280 million.

Of this total, Edison's efforts in voltage regulation, distribution circuit management, and street light conversion contributed a savings of almost 1.9 billion KWH, while customer response to Company conservation programs, including customer cogeneration, contributed a savings of 3.7 billion KWH.

Energy audits helped commercial, industrial, agricultural and public authority customers to achieve a total savings of 1.4 billion KWH and a demand reduction of 335 MW in 1983. SCE's energy audit programs encompass free surveys of customer facilities to provide energy saving recommendations, and financial incentives to encourage the installation of conservation hardware.

More than 100,000 single family residential conservation service energy audits have been completed since 1981 and the free audit program was expanded to multi-family markets in 1983. Some of the more significant incentive programs offered to customers in 1983 included:

- Conservation Financing Program... Edison offers residential customers 8% loans or cash rebates to stimulate installation of energy conservation and hardware improvements. As a result of program efforts in 1983, 30,000 energy-efficient refrigerators were purchased by customers, as well as over 20,000 additional improvements including weatherization, insulation and other measures to reduce air conditioning requirements.
- Low-Income Program... In 1983, Edison continued to coordinate low-income energy conservation with other state and local agencies. These activities include the implementation of a low-income solar water heating program, and the use of State of California solar and energy conservation bank funds to install evaporative coolers and weatherization in the residences of qualified low-income customers.

Edison's load management programs are designed to shift the use of electricity from periods of peak usage to periods of reduced demand in order to defer construction of costly new generating facilities. Programs to shift 520 MW of load are already in place.

Percentage of Male, Female and Minority Employees at Year-End 1978 and 1983	Male % Year-End 1978	Male % Year-End 1983	Female % Year-End 1978	Female % Year-End 1983	Black % Year-End 1978	Black % Year-End 1983	Asian American % Year-End 1978	Asian American % Year-End 1983	American Indian % Year-End 1978	American Indian % Year-End 1983	Hispanic % Year-End 1978	Hispanic % Year-End 1983	Total Minorities % Year-End 1978	Total Minorities % Year-End 1983
Management(1)	91.4	83.5	8.6	16.5	2.2	3.7	3.7	5.9	0.6	0.5	5.4	7.5	11.9	17.6
Non-Management(2)	77.9	73.7	22.1	26.3	7.5	9.5	2.4	3.3	0.8	1.1	13.9	18.7	24.6	32.6
Total Company(3)	82.1	77.1	17.9	22.9	5.8	7.5	2.8	4.2	0.7	0.9	11.3	14.8	20.6	27.4

(1) Management employees include the "Officials" and "Professionals" Affirmative Action Categories.

(2) Non-Management employees include "Technicians," "Office and Clerical," "Craftsmen," "Operators," "Laborers," and "Service Workers."

(3) Includes all classes of employees.

The Company projects that innovative load management programs will reduce annual peak load growth from 2.4% to 2% during the next 10 years. These programs include:

• Air Conditioner Cycling... Rate options are offered to residential and commercial/industrial customers within selected climate zones who agree to allow Edison to cycle air conditioner compressors during periods of high electric demand.

• Commercial/Industrial Off-Peak Cooling... This program is aimed at reducing peak loads of large commercial/industrial customers through the installation of systems which generate and store chilled water, ice, or other cooling media during off-peak hours when electrical demand is low.

• Interruptible Tariffs... Edison's interruptible tariffs are designed to encourage large commercial and industrial customers to reduce load during periods of low generating margins. Participating customers are given monthly rebates in return for an agreement not to exceed a pre-established demand level when notified by Edison.

• Pool Pump Timing... Since 1978, Edison's residential swimming pool program has encouraged pool owners to install time clock trippers to avoid the operation of pool filter pumps, pool sweeps and spa pumps during hours of peak summer electrical demand.

• Residential Demand Subscription Service (DSS) ... With CPUC approval, a test DSS program was initiated in 1981 and an expanded test is now being conducted. DSS offers reduced rates to participating residential customers through the meter installation of Edison developed and patented remote controllers which limit electric usage during critical periods of peak demand.

Affirmative Action

The number of minority and female employees in the Company's work force continued to increase during the year with minority group employment rising to 27.4% from 26.3% in 1982. Female employees represented 22.9% of the work force at year-end, compared to 21.9% at the beginning of 1983.

The upward mobility of both minority and female employees into management positions also has been increasing. During the five-year period from 1978 through 1983, minority management positions increased to 17.6% from 11.9% and female management positions increased to 16.5% from 8.6%.

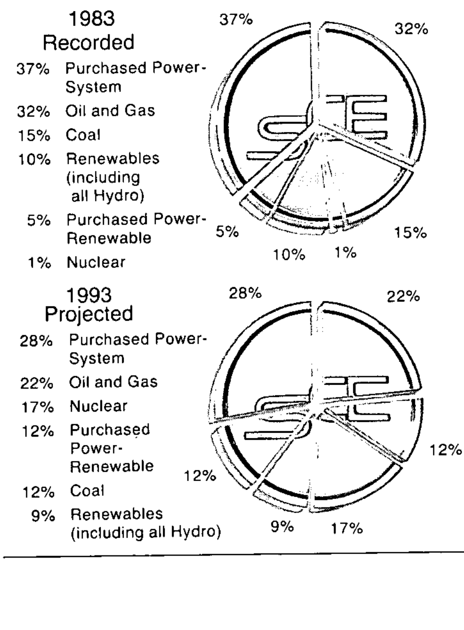
Edison's Procurement Division provided increased opportunities to Minority Business Enterprises in 1983, and female-owned enterprises were added to the program. In 1983, $25 million was paid to female and minority businesses, compared to $3.7 million paid to minority contractors in 1979 when the program was formally introduced.

In addition, the number of opportunities to compete for contracts annually has grown from 923 in 1979 to 6,467 in 1983, an increase of more than 600%. Over the same period, the number of contractors qualified to provide goods and services to Edison has more than doubled from 207 to 458.

	CAPACITY (MW)	
Nuclear		1490
Purchases		1380
Alternative/Renewables Proven Technologies		1260
Hydro	300	
Small Hydro	140	
Cogeneration	820	
Emerging Technologies		930
Wind	200	
Geothermal	275	
Solar	300	
Synthetic Fuels	100	
Fuel Cells	55	
Total		5060
Load Management		860

Planned Resource Additions 1984–1993

More than three years ago the Company announced its commitment to accelerate the development of alternative and renewable energy resources. At the end of 1983, the Company was ahead of schedule, with cogeneration, wind, solar, and biomass being the pacesetters.



Generation Fuel Mix

By 1993, Edison's generation fuel mix is anticipated to shift away from a dependence on oil and gas to a more balanced fuel mix. The Company expects to receive approximately equal amounts of energy from system purchases, oil and gas, nuclear, and renewables (both Edison-owned and third-party), with coal also making a significant contribution.

Financial Review

The Company continued to strengthen its financial condition during the year, as measured by several important financial indicators:

- Earnings per share of common stock rose 21% over the 1982 level.
- The Company earned a 17% rate of return on common equity.
- Interest coverage increased significantly to 3.44 times.
- The level of funds required for Edison's construction program declined in 1983, and projected total construction expenditures for the next five years are lower than those of the past five years.
- San Onofre Unit 2 was placed into service and began producing cash earnings.

As a result, Edison's external financial requirements in 1983 were lower than those of the previous year for the first time in eight years.

Stock Price Improves

With the general upturn in the stock market during 1983, Edison's common stock traded, with few exceptions, at slightly above book value. The stock price has increased during seven of the past 10 years, and at year's end, had achieved a compound annual growth rate over the decade of 8%. In 1983, Edison's common stock provided a total return to shareholders of 23%, comprised of price appreciation and dividends paid. This included a price increase of 13.2% for the year, compared with 2.5% for the Moody's average of 24 electric utilities. This performance is a result of continued cost control, an aggressive dividend policy, the Company's commitment to the development of alternative and renewable resources, and a general improvement in the stock market.

Stock Split Recommended

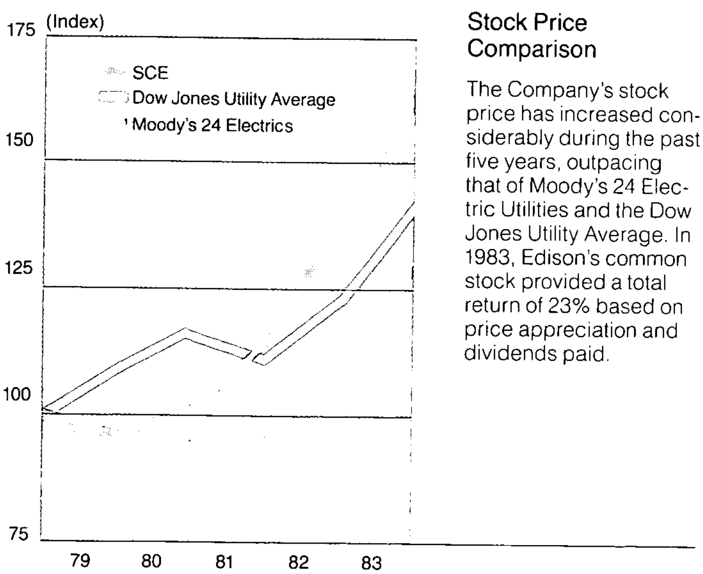
In recognition of this price appreciation and to broaden investor interest by providing a more attractive market price, the Board of Directors voted on January 19, 1984, to recommend a 2-for-1 split of the Company's common stock. Shareholders will be asked to approve the stock split at the Annual Meeting on April 19, 1984. If approved, it is expected to become effective on July 5, 1984. The Company last split its common stock in 1962.

Earnings Increase

For the 1983 calendar year, earnings per share rose 21% to $6.22, the highest in the Company's history, surpassing the $5.13 per share earned in 1982. In addition, the Company earned a 17% rate of return on common equity, outperforming the 14.9% earned in 1982. Additionally, the Company earned a 12.5% rate of return on its investment in utility plant.

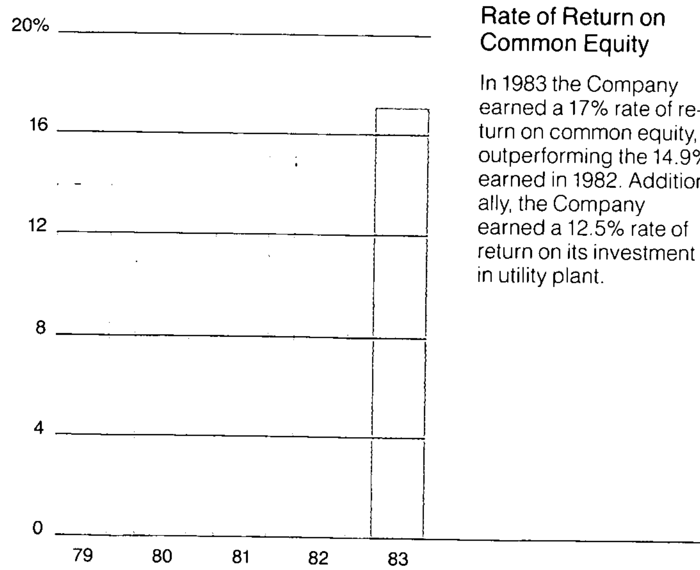
The increase in earnings primarily reflected higher non-cash allowances for funds used during construction, continuing emphasis on productivity and cost controls, and the general rate increase which became effective January 1, 1983.

In the 1983 general rate case, the CPUC established a rate-making mechanism to stabilize the level of revenue authorized regardless of fluctuations in kilowatt-hour sales. Therefore, even though kilowatt-hour sales increased 1% during 1983, the increase had little impact on earnings.



Stock Price Comparison

The Company's stock price has increased considerably during the past five years, outpacing that of Moody's 24 Electric Utilities and the Dow Jones Utility Average. In 1983, Edison's common stock provided a total return of 23% based on price appreciation and dividends paid.



Rate of Return on Common Equity

In 1983 the Company earned a 17% rate of return on common equity, outperforming the 14.9% earned in 1982. Additionally, the Company earned a 12.5% rate of return on its investment in utility plant.

Also, as part of the 1983 general rate case, the CPUC authorized an attrition allowance of $96 million to offset non-fuel inflationary increases projected for 1984. This 2% increase in customer rates, which became effective January 1, 1984, should help to maintain earnings in this year between general rate decisions.

Dividend Raised

In September 1983, the Board of Directors approved an 8% increase in the common stock quarterly dividend, raising the rate to 95¢ per share from the 88¢ established in September 1982. On an annual basis, this is equivalent to $3.80 per share, compared with the previous annual rate of $3.52. The Company implemented an aggressive dividend policy in 1977 and has increased the dividend at least once per year since then. For the past five years, the annual dividend increases have averaged 8.9%.

At year-end 1983, the dividend was providing a 9.6% yield on a common stock market value of $39¾ per share.

Financing Needs Decrease

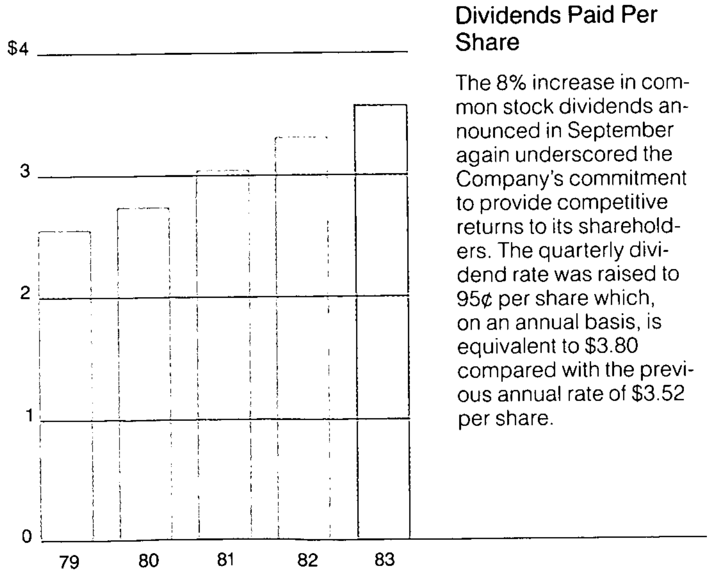
A marked increase in internally generated funds combined with the decline in construction expenditures reduced the amount of external financing undertaken by the Company in 1983. During the year, the Company raised $400 million from external sources compared to $956 million and $1,080 million required in 1981 and 1982, respectively. This is the lowest level of external financing undertaken by the Company since 1978.

Details of the Company's 1983 financing activities are set out in the following table:

Month	Issue	Term (years)	Coupon Rate	Amount (millions)
January	Pollution Control Refunding Bonds—Four Corners Generating Station	20	9⅞%	$ 88
April	Euro-Debentures	7	10½	75
May	Pollution Control Refunding Bonds—Four Corners Generating Station	20 30	8⅞ 9	20 71
Ongoing	Dividend Reinvestment and Stock Purchase Plan			84
	Employee Stock Purchase Plan			36
	Employee Stock Ownership Plan			26
	TOTAL			$400*

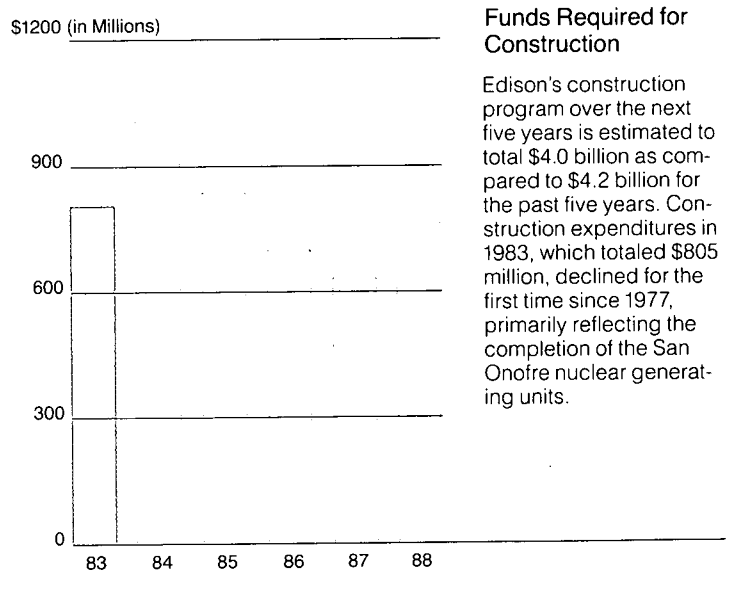
*Of this amount, $229 million represents the refundings of previously issued bonds, plus the retirement of maturing series K bonds, with the remainder of $171 representing new capital.

As noted in the table, the Company's 1983 equity capital needs were satisfied solely through the ongoing sales of common stock through the Dividend Reinvestment Plan, Employee Stock Purchase Plan and Employee Stock Ownership Plan. This marked the first year since 1979 that the Company has not undertaken a major public offering of common stock.



Dividends Paid Per Share

The 8% increase in common stock dividends announced in September again underscored the Company's commitment to provide competitive returns to its shareholders. The quarterly dividend rate was raised to 95¢ per share which, on an annual basis, is equivalent to $3.80 compared with the previous annual rate of $3.52 per share.



Funds Required for Construction

Edison's construction program over the next five years is estimated to total $4.0 billion as compared to $4.2 billion for the past five years. Construction expenditures in 1983, which totaled $805 million, declined for the first time since 1977, primarily reflecting the completion of the San Onofre nuclear generating units.

The Company also completed a tax-exempt financing strategy for pollution control facilities at the Four Corners coal-fired generating station located in New Mexico. In early 1981, the Company identified $260 million of facilities which qualified for low-cost tax-exempt financing. At that time, however, interest rates for long-term pollution control bonds were extremely high, surpassing 14% at one point. Therefore, the Company implemented a strategy of initially financing the facilities on a short-term, three-year basis with the expectation of refinancing these bonds on a long-term basis if interest rates declined.

At the end of 1982, interest rates did decline significantly, and the Company began systematically refinancing the short-term bonds on a long-term basis. On June 8, 1983, the final portion of the short-term pollution control bonds was refinanced at a rate of just under 9%. The total interest savings resulting from this financing strategy was approximately $8½ million per year.

The Company also took the opportunity to place $75 million of debentures in the European market in April when, during a brief period, interest rates reached a four-year low. With this financing, the Company now has placed a total of $450 million in the European market on seven separate occasions, all at rates below levels then existing in the domestic market.

Reflecting the $400 million of capital raised in 1983, total capitalization of the Company at year-end was $8.8 billion. SCE's capital structure at year-end 1983 was comprised of 46.3% Debt, 10.4% Preferred and Preference Stock, and 43.3% Common Equity. In the 1985 general rate case, the Company has requested ratios of 45%, 10% and 45%, respectively.

The Company's reduced need for financing also served to improve financial ratios. Most notable was the change in pretax interest coverage which improved from 2.64 times to 3.44 times during 1983.

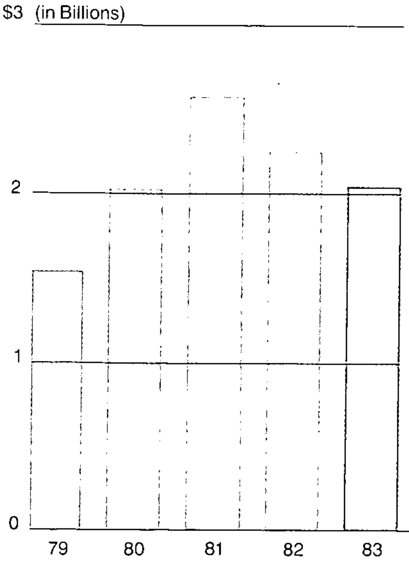
For 1984, the Company currently plans to issue approximately $300 million of tax-exempt bonds to finance pollution control facilities at the San Onofre and Palo Verde Nuclear Generating Stations. The Company has no plans to issue new shares of common stock in the public market other than through ongoing stock plans. Other financing plans are uncertain at this time.

Regulatory Matters

SCE Receives San Onofre Rate Decision:

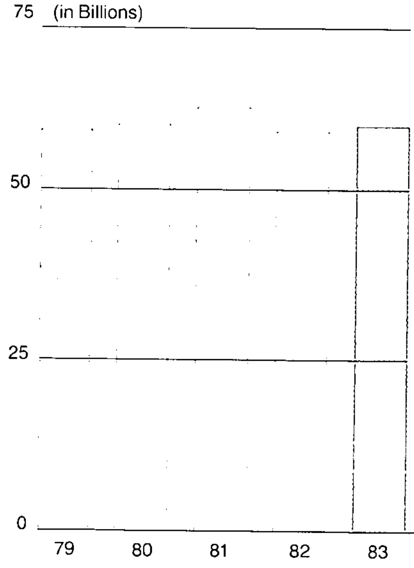
In 1983, after 13 years of design and construction, San Onofre Nuclear Unit 2 met the CPUC's criteria for commercial operation and began earning a cash return for Edison's shareholders. In California, a utility is not allowed to earn a cash return on investment in plant until the plant becomes operational.

In September 1983, the CPUC issued an initial decison to include in rates $207 million for the cost of owning, operating and maintaining San Onofre Unit 2. In November 1983, the CPUC issued a second decision granting an additional $98 million, bringing the total authorized annual rate relief for Unit 2 to $305 million. This base-rate increase was partially offset for customers by a $207 million decrease in customer rates which represented projected fuel savings associated with using nuclear fuel rather than burning oil and natural gas.



Fuel and Purchased Power Costs

1983 marked the second consecutive yearly decrease in the Company's fuel and purchased power costs. The 1983 year-end total of $2.0 billion was 9% less than in 1982 and 21% less than in 1981. This decline primarily reflects the increased availability of hydroelectric and purchased power which displaced the use of more costly fossil fuels.



Kilowatt-Hour Sales

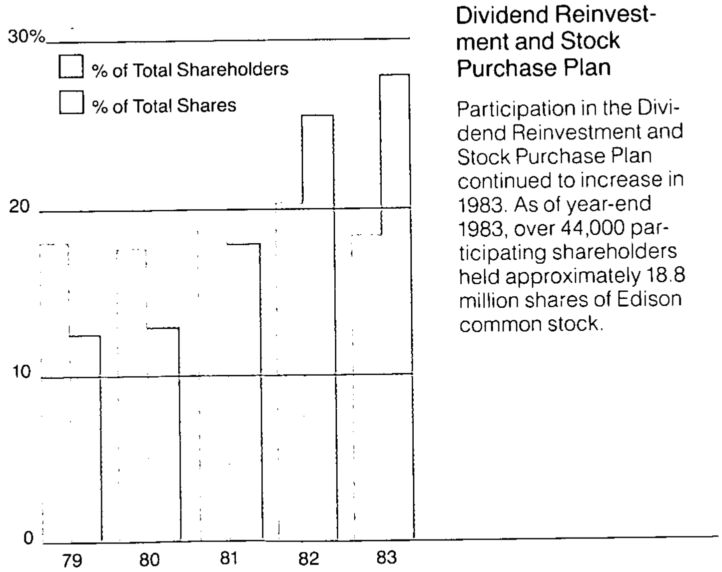
Kilowatt-hour sales changes have little impact on earnings because of the Electric Revenue Adjustment Mechanism which was designed to stabilize revenues regardless of fluctuations in kilowatt-hour sales.

A supplemental application has been filed with the CPUC for Unit 2 to reflect the updated 1984 revenue requirement of $441 million. The difference between this request and the $305 million currently authorized is being accumulated in an interest-bearing balancing account. A further decision on this filing is expected mid-year.

San Onofre Unit 3 was synchronized to Edison's system in September 1983 and is expected to meet the CPUC's commercial operating criterion during April 1984. The Company has filed a $454 million rate application for this Unit. The rate increase will be partially offset by nuclear fuel savings projected to be approximately $180 million. A decision on the Unit 3 application is expected by mid-year.

Target Capacity Factor Incentive Plan:

The CPUC included in its September 1983 decision a performance incentive plan for San Onofre Unit 2 by setting a target annual capacity factor range of 55% to 80%. Under this plan, shareholders and customers would share equally the fuel-cost savings if the plant operates above an 80% annual capacity factor. If the plant operates below a 55% annual capacity factor, additional fuel costs incurred would be divided equally between shareholders and customers. The plant averaged a 74% capacity factor from the time it was placed into service on August 8 to year-end 1983 even though the period included a five-week outage for routine maintenance and testing.



Dividend Reinvestment and Stock Purchase Plan

Participation in the Dividend Reinvestment and Stock Purchase Plan continued to increase in 1983. As of year-end 1983, over 44,000 participating shareholders held approximately 18.8 million shares of Edison common stock.

In an application for rehearing, the Company asked the CPUC to change the range from 55%–80% to 55%–75% and limit its application to events within Edison's control. In addition, the Company requested that the CPUC modify the target capacity performance incentive to include a fixed monetary cap of $25 million on a pre-tax basis for the shareholder risk related to the operation of all Company-owned nuclear units and increase the amount of operation and maintenance expense authorized in the September decision. A decision on these additional items has been deferred and is pending further Commission consideration.

CPUC Consultant's Review:

An independent consultant was retained by the CPUC to complete a review of costs incurred in constructing San Onofre Units 2 and 3. A final report from the consultant is expected late in 1984.

1985 General Rate Request Filed:

On December 29, 1983, the Company filed a general rate application with the CPUC covering capital and operating costs other than fuel. This request totaled $453 million for the test-year 1985. This reflects a 13.39% rate of return on rate base and 17.5% rate of return on common equity, compared with the current authorization of 12.65% and 16%, respectively. The Company requested this increase, averaging 8.3% in customer rates, become effective January 1, 1985.

Included in the request was an Attrition Rate Adjustment to help meet inflationary cost increases between rate-case years. Edison estimates this will increase rates in 1986 by $110 million, or 1.8% above the 1985 level. The actual amount of rate change will be determined in late 1985.

New CPUC Commissioner Appointed:

In May 1983, California Governor George Deukmejian appointed William T. Bagley to the California Public Utilities Commission. Mr. Bagley served on the California State Assembly from 1960 to 1974 and in 1978 was appointed the first Chairman of the Commodity Futures Trading Commission. His term with the CPUC began on June 1, 1983, and will expire January 1, 1985.

Responsibility for Financial Statements

The management of Southern California Edison Company has prepared and is responsible for the financial statements and the other related financial data contained in this Annual Report. The financial statements, which include amounts based on estimates and judgments of management, have been prepared in conformity with generally accepted accounting principles applied on a consistent basis.

To meet its responsibilities with respect to financial information, the Company maintains a system of internal accounting controls which is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and that the financial records properly reflect the authorized transactions of the Company. This system is supported by written policies and procedures, organization structures that provide for appropriate division of responsibility, the selection and training of qualified personnel and is augmented by programs of internal audits. There are limits inherent in all systems of internal accounting control based on the recognition that the cost of such system should not exceed the benefits to be derived. The Company believes its system of internal accounting control appropriately balances this cost-benefit relationship.

An independent examination of these financial statements has been conducted by Arthur Andersen & Co., independent public accountants, in accordance with generally accepted auditing standards. In connection therewith, the independent accountants develop and maintain an understanding of the Company's accounting and financial controls, and conduct such tests and related procedures as they deem necessary to render their opinion as to the fairness of the financial statements.

The Audit Committee of the Board of Directors, composed entirely of directors who are not officers or employees of the Company, meets periodically with the management of the Company, the independent public accountants and the internal auditors to make inquiries as to the manner in which the responsibilities of each are being discharged. In addition, the Audit Committee recommends to the Board of Directors the annual appointment of the independent public accountants with whom the Audit Committee reviews the scope of the audit and the nature of other services provided as well as the related fees, the accounting principles being applied by the Company in financial reporting, the scope of internal financial auditing procedures, and the adequacy of internal accounting controls.

To further assure independence in performing and reporting the results of audits, representatives of the independent public accountants and the Company's staff of internal auditors have full and free access to meet with the Audit Committee, without members of Company management being present, to discuss any accounting, auditing, or financial reporting matter.

Report of Independent Public Accountants

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

We have examined the balance sheets and statements of capital stock and long-term debt of Southern California Edison Company (a California corporation, hereinafter referred to as the "Company"), as of December 31, 1983 and 1982, and the related statements of income, earnings reinvested in the business, additional paid-in capital and sources of funds used for construction expenditures for each of the three years in the period ended December 31, 1983. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances, and also included similar examinations of the financial statements for each quarter within each of the years.

In our opinion, the financial statements referred to above present fairly the financial position of the Company as of December 31, 1983 and 1982, and the results of its operations and the sources of its funds used for construction expenditures for each of the three years in the period ended December 31, 1983, and further, in our opinion, the quarterly financial data set forth in Note 8 of "Notes to Financial Statements" summarize fairly the results of operations for each quarter within such years, all in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

Los Angeles, California,
February 3, 1984.

ARTHUR ANDERSEN & CO.

Southern California Edison Company

Statements of Income

		Thousands of Dollars Year Ended December 31, 1983	1982	1981
Operating Revenues:	Sales *(Note 1)*	**$4,413,619**	$4,266,950	$4,026,548
	Other	**50,637**	35,652	27,808
	Total operating revenues	**4,464,256**	4,302,602	4,054,356
Operating Expenses:	Fuel	**1,457,102**	1,778,553	2,078,393
	Purchased power *(Note 10)*	**570,654**	449,348	479,813
	Provisions for regulatory adjustment clauses *(Note 1)*	**(21,559)**	372,537	(89,472)
	Other operation expenses	**604,694**	491,613	441,138
	Maintenance	**279,916**	210,160	193,397
	Depreciation *(Note 1)*	**289,361**	220,927	202,182
	Income taxes *(Note 5)*	**497,236**	177,251	197,865
	Property and other taxes	**82,821**	65,486	59,885
	Total operating expenses	**3,760,225**	3,765,875	3,563,201
Operating Income		**704,031**	536,727	491,155
Other Income:	Allowance for equity funds used during construction *(Note 1)*	**268,831**	209,485	162,879
	Interest income	**33,272**	34,571	39,025
	Taxes on non-operating income—credit *(Note 5)*	**117,160**	100,655	54,261
	Other income and income deductions	**9,838**	965	13,896
	Total other income	**429,101**	345,676	270,061
Total Income Before Interest Charges		**1,133,132**	882,403	761,216
Interest Charges:	Interest on long-term debt	**425,075**	360,915	281,626
	Other interest and amortization *(Note 1)*	**114,302**	59,367	59,351
	Total interest charges	**539,377**	420,282	340,977
	Allowance for borrowed funds used during construction *(Note 1)*	**(97,025)**	(93,633)	(69,673)
	Net interest charges	**442,352**	326,649	271,304
Net Income		**690,780**	555,754	489,912
Dividends on Cumulative Preferred and Preference Stock		**73,477**	72,396	67,888
Earnings Available for Common and Original Preferred Stock		**$ 617,303**	$ 483,358	$ 422,024
Weighted Average Shares of Common and Original Preferred Stock Outstanding (000)		**99,174**	94,257	85,610
Earnings Per Share *(Note 1)*		**$6.22**	$5.13	$4.93
Dividends Declared Per Common Share		**$3.66**	$3.38	$3.10

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

Southern California Edison Company

Balance Sheets

Assets

		Thousands of Dollars December 31, 1983	1982
Utility Plant:	Utility plant, at original cost *(Notes 1 and 9)*	**$ 8,883,519**	$ 6,609,540
	Less—Accumulated depreciation *(Notes 1 and 9)*	**2,426,368**	2,185,667
		6,457,151	4,423,873
	Construction work in progress *(Note 9)*	**2,940,356**	4,108,878
	Nuclear fuel, at amortized cost	**62,735**	45,660
		9,460,242	8,578,411
	Less—Property-related accumulated deferred income taxes *(Notes 1 and 5)*	**256,629**	79,084
		9,203,613	8,499,327
Other Property and Investments:	Nonutility property and other investments, at cost—less accumulated depreciation	**19,138**	11,383
	Investments in and advances to subsidiaries *(Note 1)*	**113,595**	104,378
		132,733	115,761
Current Assets:	Cash and equivalents *(Note 4)*	**254,352**	120,661
	Cash investments—financing subsidiary *(Note 1)*	**157,321**	127,849
	Receivables, less reserves of $10,551,000 and $8,105,000 for uncollectible accounts at respective dates	**300,691**	306,041
	Fuel stock, at cost (first-in, first-out) *(Note 4)*	**450,555**	605,162
	Materials and supplies, at average cost	**71,625**	64,185
	Accumulated deferred income taxes—net *(Note 5)*	**217,690**	198,939
	Prepayments and other	**53,901**	42,563
		1,506,135	1,465,400
Deferred Charges:	Unamortized debt expense *(Note 1)*	**31,122**	29,169
	Accumulated deferred income taxes—net *(Note 5)*	**101,302**	21,892
	Other deferred charges	**60,155**	26,015
		192,579	77,076
		$11,035,060	$10,157,564

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

Capitalization and Liabilities

		Thousands of Dollars December 31, 1983	1982
Capitalization:	Common stock, at par value, 100,740,155 and 96,691,973 shares outstanding at respective dates *(Note 1)*	**$ 839,501**	$ 805,766
	Additional paid-in capital *(Note 1)*	**1,307,546**	1,193,318
	Earnings reinvested in the business	**1,646,292**	1,393,780
	Common shareholders' equity	**3,793,339**	3,392,864
	Preferred and preference stock without mandatory redemption requirements	**469,025**	471,020
	Preferred and preference stock with mandatory redemption requirements	**440,500**	445,000
	Long-term debt *(Note 1)*	**4,051,836**	3,970,400
		8,754,700	8,279,284
Current Liabilities:	Long-term debt due within one year	**83,000**	53,500
	Preferred stock to be redeemed within one year	**4,500**	4,500
	Short-term borrowings *(Note 4)*	**43,670**	23,992
	Short-term borrowings—financing subsidiary *(Notes 1 and 4)*	**154,300**	123,300
	Accounts payable	**364,456**	411,240
	Accrued taxes *(Note 5)*	**307,403**	166,139
	Accrued interest	**123,162**	112,666
	Dividends payable	**101,150**	90,636
	Regulatory balancing accounts—net *(Note 1)*	**376,248**	369,317
	Other	**58,159**	47,696
		1,616,048	1,402,986
Deferred Credits and Reserves:	Accumulated deferred investment tax credits *(Note 5)*	**343,696**	274,280
	Customer advances and other deferred credits	**251,084**	146,877
	Reserves for pensions, insurance, etc. *(Note 7)*	**69,532**	54,137
		664,312	475,294
Commitments and Contingencies *(Notes 2, 3, and 10)*			
		$11,035,060	$10,157,564

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

Statements of Sources of Funds Used for Construction Expenditures

		Thousands of Dollars		
		Year Ended December 31,		
		1983	1982	1981
Funds Provided By—				
Operations:	Net income	**$690,780**	$555,754	$489,912
	Non-cash items in net income—			
	Depreciation	**289,361**	220,927	202,182
	Allowance for equity and borrowed funds used during construction	**(365,856)**	(303,118)	(232,552)
	Property-related deferred income taxes	**177,545**	53,112	(993)
	Investment tax credits deferred—net	**69,416**	64,612	47,386
	Other—net	**(33,093)**	46,497	4,694
	Total funds from operations	**828,153**	637,784	510,629
	Dividends	**(438,135)**	(395,103)	(336,546)
	Total funds from operations—reinvested	**390,018**	242,681	174,083
Long-term Financing:	Sales of securities—			
	Common stock (a)	**147,799**	264,634	292,356
	Preferred stock	**—**	49,474	—
	Long-term debt (b)	**130,848**	576,864	634,435
	Increase in other long-term debt	**26,099**	—	—
	Reduction for long-term debt due within one year—net	**(83,000)**	(53,500)	(121,025)
	Reduction for preferred stock to be redeemed within one year	**(4,500)**	(4,500)	—
	Conversion of preference stock	**(1,995)**	(5,290)	(6,344)
	Total funds from long-term financing	**215,251**	827,682	799,422
Other Sources (Uses) of Funds—	Working capital changes—			
	Cash and equivalents and cash investments	**(163,163)**	(238,101)	(2,767)
	Receivables—net	**5,350**	226	(17,288)
	Fuel stock and materials and supplies	**147,167**	(26,517)	(880)
	Accumulated deferred income taxes—net	**(18,751)**	(194,067)	24,471
	Long-term debt and preferred stock due within one year	**29,500**	(63,025)	(22,523)
	Net short-term borrowings	**50,678**	(147,895)	110,214
	Accounts payable	**(46,784)**	51,222	3,678
	Accrued taxes	**141,264**	104,365	(60,142)
	Regulatory balancing accounts—net	**6,931**	405,908	(74,109)
	Other changes in working capital	**20,135**	1,316	31,174
	Net (increase) decrease in working capital	**172,327**	(106,568)	(8,172)
	Sale of non-current assets	**—**	—	50,623
	Other—net	**27,901**	30,108	(59,193)
	Total other sources (uses) of funds	**200,228**	(76,460)	(16,742)
Funds Used for Construction Expenditures		**$805,497**	$993,903	$956,763

(a) Includes conversions of Preference Stock, 5.20% Convertible Series, to Common Stock.
(b) Includes reduction for funds held by trustees for construction of pollution control facilities.

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

Statements of Earnings Reinvested in the Business

		Thousands of Dollars		
		Year Ended December 31,		
		1983	1982	1981
Balance at January 1		**$1,393,780**	$1,238,317	$1,092,137
Add:	Net income	**690,780**	555,754	489,912
		2,084,560	1,794,071	1,582,049
Deduct:	Dividends declared on capital stock—			
	Common—$3.66 per share for 1983, $3.38 per share for 1982 and $3.10 per share for 1981	**362,935**	321,118	267,204
	Original Preferred	**1,723**	1,589	1,454
	Cumulative Preferred	**68,540**	67,291	62,504
	Preference	**4,937**	5,105	5,384
	Capital stock expense	**133**	5,188	7,186
		438,268	400,291	343,732
Balance at December 31 (a)		**$1,646,292**	$1,393,780	$1,238,317

(a) Includes undistributed earnings of unconsolidated subsidiaries of $11,185,000 and appropriated earnings related to certain federally-licensed hydroelectric projects of $3,932,000 at December 31, 1983.

Statements of Additional Paid-in Capital

		Thousands of Dollars		
		Year Ended December 31,		
		1983	1982	1981
Balance at January 1 *(Note 1)*		**$1,193,318**	$ 999,764	$805,325
	Premium received on sale of Common Stock and conversion of Preference Stock	**114,228**	193,554	194,439
Balance at December 31		**$1,307,546**	$1,193,318	$999,764

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

Southern California Edison Company

Statements of Capital Stock

		Shares Outstanding (December 31, 1983)	Redemption Price Per Share (December 31, 1983)	Stated Value—December 31, 1983 (Thousands of Dollars)	Stated Value—December 31, 1982 (Thousands of Dollars)
Common Stock—authorized 140,000,000 shares, par value $8⅓ per share (a) (b) (d):		100,740,155	—	**$839,501**	$805,766
Preferred and Preference Stock—without Mandatory Redemption Requirements (c):					
Original Preferred—5%, prior, cumulative, participating, not redeemable, par value $8⅓ per share		480,000	—	**$ 4,000**	$ 4,000
Cumulative Preferred—par value $25 per share:	4.08% Series	1,000,000	$ 25.50	**25,000**	25,000
	4.24% Series	1,200,000	25.80	**30,000**	30,000
	4.32% Series	1,653,429	28.75	**41,336**	41,336
	4.78% Series	1,296,769	25.80	**32,419**	32,419
	5.80% Series	2,200,000	25.25	**55,000**	55,000
	8.85% Series	2,000,000	26.50	**50,000**	50,000
	9.20% Series	2,000,000	26.50	**50,000**	50,000
$100 Cumulative Preferred—par value $100 per share:	7.58% Series	750,000	102.50	**75,000**	75,000
	8.70% Series	500,000	107.00	**50,000**	50,000
	8.96% Series	500,000	107.00	**50,000**	50,000
Preference—par value $25 per share (a) (b) (d):	5.20% Convertible Series	250,792	25.00	**6,270**	8,265
$100 Preference—par value $100 per share		—	—	**—**	—
				$469,025	$471,020
Preferred and Preference Stock—with Mandatory Redemption Requirements (c) (e):					
$100 Cumulative Preferred—par value $100 per share:	7.325% Series	720,000	$104.80	**$ 72,000**	$ 75,000
	7.80% Series	584,998	110.00	**58,500**	60,000
	8.54% Series	750,000	108.54	**75,000**	75,000
	8.70% Series A	525,000	110.00	**52,500**	52,500
	12.00% Series	750,000	112.00	**75,000**	75,000
	12.31% Series	500,000	105.83	**50,000**	50,000
Preference—par value $25 per share:	7.375% Series	2,480,000	25.25	**62,000**	62,000
				445,000	449,500
Less: Preferred Stock to be redeemed within one year				**(4,500)**	(4,500)
				$440,500	$445,000

(a) Under a prescribed formula, the conversion price of the Preference Stock, 5.20% Convertible Series is adjusted when additional shares of Common Stock are sold by the Company. As of December 31, 1983, the conversion price was $31.50 per share. The 12½% Convertible Subordinated Debentures Due 1997, issued by Southern California Edison Finance Company N.V., are convertible into Company Common Stock at the conversion price of $32.375 per share.

(b) At December 31, 1983, shares of Common Stock were reserved for issuance as follows:

	Shares
Conversion of Preference Stock, 5.20% Convertible Series	199,040
Conversion of 12½% Convertible Subordinated Debentures, Due 1997, issued by Southern California Edison Finance Company N.V.	1,600,000
Stock purchase plans	8,369,844*
Total	10,168,884

*These plans include the Dividend Reinvestment and Stock Purchase Plan (DRP), Employee Stock Purchase Plan (ESPP) and Employee Stock Ownership Plan (ESOP). The Company has issued 644,542 shares of Common Stock under these plans since December 31, 1983.

(c) As of December 31, 1983, shares authorized for the Original Preferred, Cumulative Preferred, $100 Cumulative Preferred, Preference and $100 Preference Stock were 480,000, 24,000,000, 12,000,000, 10,000,000, and 2,000,000 shares, respectively. All series of Cumulative Preferred, $100 Cumulative Preferred and Preference Stock are redeemable at the option of the Company. The 500,000 shares of $100 Cumulative Preferred Stock, 12.31% Series, are not subject to such redemption until May 1, 1992. The various series of the $100 Cumulative Preferred Stock, and the Preference Stock, 7.375% Series, are subject to certain restrictions on redemption for refunding purposes.

(d) Transactions in the capital stock accounts during 1983, 1982 and 1981 reflect the following:
Shares of Common Stock were issued through public offerings and stock purchase plans, and the conversion of 79,825, 211,522 and 253,761 shares in the respective years of Preference Stock, 5.20% Convertible Series (5.20% Series) as follows:

Shares Issued	1983	1982	1981
Public offerings	—	5,000,000	8,000,000
DRP	2,328,994	2,498,253	1,906,474
ESPP	953,711	820,752	1.053,413
ESOP	702,200	601,948	591,084
5.20% Series	63,277	167,748	198,483

(e) For Preferred and Preference Stock with Mandatory Redemption Requirements, the aggregate mandatory redemption requirements for the five years subsequent to December 31, 1983 are as follows:

	No. of Shares	Commencing	1984 (Thousands of Dollars)	1985	1986	1987	1988
$100 Cumulative Preferred							
7.325%	30,000	7/31/83	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
7.80%	15,000*	11/30/83	1,500	1,500	1,500	1,500	1,800
8.54%	22,500	6/30/86	—	—	2,250	2,250	2,250
8.70%A	13,125	6/30/85	—	1,313	1,313	1,313	1,313
12.00%	22,500	12/31/86	—	—	2,250	2,250	2,250
12.31%	35,000	4/30/88	—	—	—	—	3,500
Preference							
7.375%	496,000	2/01/85	—	12,400	12,400	12,400	12,400
			$ 4,500	$18,213	$22,713	$22,713	$26,513

*Increases to 18,000 shares beginning in 1988.

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

Statements of Long-term Debt

Issue and Maturity		Interest Rates	Thousands of Dollars December 31, 1983	1982
First and Refunding Mortgage Bonds (a) (c) (d):				
	Due 1983 through 1987	4¼%–10%	**$ 511,800**	$ 561,800
	Due 1988 through 1992	4⅜%–15¼%	**615,000**	615,000
	Due 1993 through 1997	6⅜%–8⅛%	**600,000**	600,000
	Due 1998 through 2002	7%–8⅞%	**515,030**	515,030
	Due 2003 through 2007	8⅞%–15⅛%	**813,000**	705,000
	Due 2008 through 2021	9%–16%	**834,300**	763,300
			3,889,130	3,760,130
First Mortgage Bonds (Calectric) (a) (c)	Due 1984 through 1991	3¼%–5⅛%	**60,000**	60,000
Promissory Notes	Due 1983	5½%	**—**	3,500
Promissory Notes (b) (c)	Due 1986 through 1997	11%–16¾%	**450,000**	375,000
Pollution Control Indebtedness (d)		8⅛%	**92,500**	92,500
Principal amounts outstanding			**4,491,630**	4,291,130
Long-term debt due within one year—net (c)			**(83,000)**	(53,500)
Unamortized debt premium or (discount)—net			**(20,996)**	(22,024)
Securities held by trustees (d)			**(361,897)**	(245,206)
			4,025,737	3,970,400
Other long-term debt (e)			**26,099**	—
Total long-term debt			**$4,051,836**	$3,970,400

(a) The authorized principal amount of each series of First and Refunding Mortgage Bonds is equal to the amount outstanding. The Trust Indenture under which these bonds are issued permits the issuance from time to time of additional bonds, including additional bonds equal in principal amount to bonds retired, pursuant to the restrictions and conditions contained therein. Substantially all of the properties of the Company are subject to the lien of the Trust Indenture. The Trust Indenture requires semi-annual deposits with the Trustees of 1½% of the principal amount of the Company's outstanding First and Refunding Mortgage Bonds and the Calectric First Mortgage Bonds. The Calectric Indenture requires an annual cash deposit with the Trustee of 1% of the principal amount of Calectric First Mortgage Bonds issued or 166⅔% of such amount if property additions are used to satisfy the annual deposit requirements. In addition, an amount equivalent to the excess of 15% of defined operating revenues over costs of maintenance of the property subject to the lien of such indenture is required to be deposited with the Trustee annually. These deposit requirements of such indentures may be or have been satisfied by property additions and replacements, and by delivery and cancellation of bonds outstanding under the applicable indenture.

(b) Promissory Notes payable to Southern California Edison Finance Company N.V. (Finance) have been issued in exchange for the proceeds from the issuance of Debentures by Finance. Payment of the principal and interest on $400,000,000 and $50,000,000 principal amount of the Debentures are, respectively, unconditionally guaranteed and guaranteed on a subordinated basis by the Company. The Subordinated Debentures are convertible into the Company's Common Stock.

(c) Maturities and sinking fund requirements of long-term debt for the five years subsequent to December 31, 1983 are as follows:

Year Ended December 31,	Thousands of Dollars Maturities	Sinking Fund Requirements	Total
1984	$ 83,000	$ —	$ 83,000
1985	96,000	5,250	101,250
1986	113,000	5,250	118,250
1987	196,000	5,250	201,250
1988	122,000	5,250	127,250

(d) First and Refunding Mortgage Bonds and other indebtedness have been issued to different municipalities and other governmental agencies in exchange for the proceeds from the issuance of Pollution Control Revenue Bonds and Pollution Control Revenue Refunding Bonds. The Company is obligated to pay the principal and interest on these bonds. The proceeds have been deposited with Trustees and are being utilized to defray the construction and other specified costs of pollution control facilities and retirement of maturing issues. During February 1984, the Company plans to enter into a loan agreement with the California Pollution Control Financing Authority pursuant to which the Company will be obligated to pay principal and interest on approximately $195,000,000 principal amount of the Authority's Floating Rate Monthly Demand Pollution Control Revenue Bonds. The proceeds of the Authority's bonds will be used to reimburse the Company for certain costs incurred for air and water pollution control and solid waste disposal facilities at the San Onofre Nuclear Generating Station.

(e) Pursuant to the Nuclear Waste Policy Act of 1982 (Act), the Company has entered into a contract with the U.S. Department of Energy for disposal of spent nuclear fuel for the San Onofre Nuclear Generating Station. For nuclear generation prior to April 7, 1983, the Act provides for a one-time fee equivalent to an average charge of 1.0 mil per kilowatt hour. Interest on the one-time fee is accrued and compounded quarterly at the rate of the first 13-week Treasury Bill issuance in each calendar quarter as published by the Federal Reserve. The weighted-average rate used for the year ended December 31, 1983, was 8.39%. The Act does not require selection of payment method until June 30, 1985.

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

Notes to Financial Statements

Note 1—Summary of Significant Accounting Policies

General—
The Company is a public utility primarily engaged in the business of supplying electric energy in portions of central and southern California, excluding the City of Los Angeles and certain other cities. The accounting records of the Company are maintained in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the California Public Utilities Commission (CPUC).

Utility Plant—
The cost of additions and replacements of retirement units of property is capitalized and included in utility plant. Such cost includes labor, material, indirect charges for engineering, supervision, transportation, etc., and an allowance for equity and borrowed funds used during construction (AFUDC). The amount of AFUDC capitalized is also reported in the Statements of Income as a reduction of interest charges for the borrowed funds component of AFUDC and as other income for the equity funds component. Although AFUDC increases net income, it does not represent current cash earnings. The AFUDC rate, which is based upon a formula prescribed by the FERC, was 9.95%, 9.20%, and 8.77% for the years 1983, 1982, and 1981, respectively.

The cost of minor additions and repairs is charged to maintenance expense and the original cost, less net salvage, of retired property units is charged to accumulated depreciation.

Property-related accumulated deferred income taxes reflect the consumption of the value of plant and equipment to which they relate and have been deducted from utility plant. This treatment is consistent with the method utilized in ratemaking proceedings to determine the rate base upon which the Company is entitled to earn a return.

Depreciation—
For financial reporting purposes, depreciation of utility plant is computed on a straight-line remaining life basis and approximated 4.1%, 3.6% and 3.6% of average depreciable plant for the years 1983, 1982 and 1981, respectively. The Company's rates are designed to recover the original cost of utility plant, including the estimated decommissioning costs for the San Onofre Nuclear Generating Station (San Onofre) units in service, through depreciation expense over the estimated remaining useful lives of the facilities. As of December 31, 1983, rates reflected the estimated decommissioning cost of $173,415,000 applicable to San Onofre Units 1 and 2.

Income Taxes—
Accounting policies with respect to income taxes and related investment tax credits are set forth in Note 5.

Debt Premium and Discount—
Debt premium or discount and related expenses are amortized to income over the lives of the issues to which they pertain.

Revenues and Regulatory Balancing Accounts—
Customers are billed monthly on a cycle basis and revenues are recorded when customers are billed. As authorized by the CPUC, the Company has established several regulatory balancing accounts which remove the effect on earnings of fluctuations in kilowatt-hour sales, fuel and purchased power costs and certain conservation program expenses. Effective January 1, 1983, an Electric Revenue Adjustment Mechanism was established to account for differences between authorized and recorded base rate revenues caused by, among other things, fluctuations in kilowatt-hour sales levels. The Energy Cost Adjustment Clause (ECAC) balancing account is used by the Company to record monthly entries to adjust the results of operations for variations between 90% of recorded fuel and purchased power costs and those included in rates billed to customers. Such variations are deferred and accumulated in the balancing account until they are refunded to, or recovered from, utility customers through CPUC-authorized rate adjustments. ECAC-related fuel and purchased power costs include incurred transportation and interim storage costs related to spent nuclear fuel. The Company has been authorized Annual Energy Rate (AER) revenues to recover 10% of forecasted fuel and purchased power costs. The ECAC balancing account is used to record monthly AER entries to adjust the results of operations for variations, between such costs and the AER revenues, in excess of $43,400,000 on an annualized basis as of December 31, 1983.

A Major Additions Adjustment Clause (MAAC) has been established to include in rates the cost of owning and operating San Onofre Unit 2. The rates became effective October 9, 1983 and were subsequently increased, effective January 1, 1984. Under MAAC, a balancing account is utilized to record differences in investment-related costs and rates authorized by the CPUC to cover such costs. The CPUC has also established a performance incentive plan for San Onofre Unit 2 which sets a target capacity factor range of 55% to 80%. The fuel savings or costs for operations above or below the target capacity factor range will be split equally between the Company's shareholders and customers.

Interest is accrued on the regulatory balancing accounts at the most recent three-month prime commercial paper rate as published by the Federal Reserve. The weighted-average rate used for the year ended December 31, 1983 was 8.85%. The income tax effects of the regulatory balancing account variations are deferred. Billed revenues and incurred balancing account costs are utilized in the determination of taxable income.

Subsidiaries—
The Company's investments in unconsolidated subsidiary companies, all of which are wholly-owned, are accounted for by the equity method except for the Company's subsidiaries engaged in Eurodebenture financings. For these subsidiaries, cash investments and short-term borrowings are presented separately on the balance sheet of the Company. None of the Company's other wholly-owned subsidiaries are considered significant for financial reporting purposes.

Earnings Per Share—
Earnings per share are determined by dividing the earnings available for Common and Original Preferred Stock by a weighted average number of such shares outstanding. After providing for cumulative preferred and preference stock dividend requirements, effect is given to the participating provisions of the Original Preferred Stock and Common Stock Equivalents for funds held for the purchase of Company Common Stock by the Employee Stock Purchase Plan Trustee in each period. The dilutive effect on earnings per share of the conversion of the 5.20% Convertible Series Preference Stock issued by the Company and the 12½% Convertible Debentures issued by Southern California Edison Finance Company N.V., an affiliate of the Company, is not significant.

Reclassifications—
The amounts shown for Common Stock are presented at par value. Amounts in excess of par value are included in Additional Paid-in Capital. Prior period amounts have been reclassified to make them comparable to the classifications at December 31, 1983. Certain other items have been reclassified in prior periods to make them comparable to the classifications at December 31, 1983.

Note 2—Commitments and Contingencies

Construction Program and Fuel Supply—
The Company has significant purchase commitments in connection with its continuing construction program. As of December 15, 1983 (the date of the Company's latest approved budget), funds required for construction expenditures are estimated at $1,023,000,000 for 1984, $850,000,000 for 1985 and $701,000,000 for 1986.

Minimum long-term commitments of approximately $1,600,000,000, exclusive of the Chevron contract discussed below, existed on December 31, 1983 under the Company's fuel supply and transportation arrangements.

Nuclear Waste Policy Act—
Pursuant to the Nuclear Waste Policy Act of 1982 (Act), the Company, acting as agent for the San Onofre Participants, has entered into a contract with the U.S. Department of Energy (DOE) for disposal of spent nuclear fuel for San Onofre Units 1, 2 and 3. The Company estimates that, before reduction to present value, the Company's portion of the obligation under this contract would approximate $340,100,000 over the lives of its nuclear generating units at San Onofre. The amount charged to income for the year ended December 31, 1983 was $2,185,000. There were no charges to income for this fee in 1982 or 1981. Recovery of the expenses associated with disposal of spent nuclear fuel was authorized through base rates until December 31, 1983. Effective January 1, 1984 such costs will be recovered through the Company's ECAC procedures.

Fuel Supply Litigation—
The Company entered into a contract (for the period January 1, 1978 through June 30, 1986) with Chevron U.S.A. Inc. (Chevron) to purchase fuel for generation. Due to environmental, economic, regulatory and other factors, the Company reduced, and then suspended (commencing April 1, 1982), its fuel deliveries under the contract. On May 19, 1982, the Company sent a notice to Chevron which, among other things, terminated the contract effective June 24, 1982. Chevron disputes the effectiveness of this notice. On July 26, 1982, the Company sent an additional notice to Chevron which, while preserving the Company's rights under the May 19 notice, gave notice of termination under two other sections of the contract, which terminations became effective as of October 25, 1982 and January 31, 1983, respectively.

On April 30, 1982, Chevron filed an action against the Company in the Superior Court of the State of California for the City and County of San Francisco for declaratory relief and breach of contract. Chevron alleged that the Company has no contractual basis to reduce below certain levels or suspend deliveries of fuel, or terminate the contract. Chevron did not specify the amount of damages alleged to have been incurred. Chevron did seek a ruling that the Company would be obligated to pay a "facility charge" (approximately $8,300,000 a month) during the remaining contract term. The Company disagrees with Chevron's interpretation of the contract and with many of Chevron's allegations. The Company believes that it has substantial affirmative defenses and intends to vigorously defend the Chevron action.

Notes to Financial Statements (Continued)

On August 2, 1982, the Company filed a cross-complaint against Chevron seeking, among other things, a declaratory judgment that the Company properly and effectively terminated the subject contract and the return from Chevron of approximately $12,000,000 in underlift payments made by the Company to Chevron in the last half of 1981 on a provisional basis.

On October 28, 1983, Chevron filed a motion for a summary judgment that the Company is obligated to pay the facility charge throughout the term of the contract. The motion is set to be heard on April 4, 1984.

If Chevron is finally successful in pursuing its present position and if rate recovery of the Company's costs under or resulting from the contract is not allowed, the Company's financial exposure would be material. Although the Company cannot predict with certainty whether the CPUC and the FERC will allow the Company to recover its costs under or resulting from the contract, the Company expects to include any such costs in existing or special fuel cost recovery proceedings and believes that such costs are a proper item for recovery through rates.

Nuclear Insurance—
The Price-Anderson Act currently limits the public liability claims that could arise from a nuclear incident to a maximum amount of $580,000,000 for each licensed nuclear facility. The Company and the co-owners of San Onofre have purchased primary insurance for this exposure in the maximum available amount, presently $160,000,000, with the balance to be provided by secondary financial protection required by the Nuclear Regulatory Commission (NRC). Under the agreement with the NRC, the Company could be assessed retrospective premium adjustments, of up to $30,000,000, in the event of nuclear incidents involving any licensed reactors in the United States.

Property damage coverage is provided for losses up to $500,000,000 at San Onofre. The Company has also purchased decontamination liability and property damage insurance in excess of the primary $500,000,000 layer. Insurance to cover a portion of the additional expense of replacement power resulting from an accident-related outage of a nuclear unit is also provided. A maximum weekly indemnity in the amount of $2,500,000 for a single unit for 52 weeks commences after the first 26 weeks. An additional $1,250,000 per week is provided for the next 52 weeks. These policies are primarily provided through mutual insurance companies owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangements were to exceed the accumulated funds available for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $114,800,000.

The premiums for the insurance policies discussed above are charged to Operating Expenses currently unless they relate to facilities under construction, in which case the premiums are charged to construction work in progress. At December 31, 1983, the nuclear insurance coverages for San Onofre are summarized as follows:

	Millions of Dollars	
Type and Source of Coverage	Maximum Coverage	Maximum Annual Retrospective Assessment
Public Liability:		
Private Insurance	$ 160.0	$ —
Nuclear Regulatory Commission Assessments	420.0	30.0
	$ 580.0	$ 30.0
Property Damage	$ 500.0	$ 96.0
Excess Property Damage and Decontamination Liability	$ 493.0	$ 11.0
Replacement Power	$ 195.0	$ 7.8

Government Licenses—
The terms and provisions of licenses granted by the United States cover the Company's major and certain minor hydroelectric plants, with a total effective operating capacity of 897.5 megawatts. These licenses also cover certain storage and regulating reservoirs and related transmission facilities. All of the above licenses expire at various times between 1984 and 2009. The licenses contain numerous restrictions and obligations on the part of the Company, including the right of the United States to acquire Company properties or, under certain conditions, the FERC to issue a license to a new licensee upon the payment to the Company of specified compensation. Applications of the Company for the relicensing of certain hydroelectric plants referred to above with aggregate effective operating capacity of 31.8 megawatts are pending. Any new licenses to the Company are expected to be issued upon terms and conditions less favorable than those of the expired licenses.

Resale Revenues—
Pursuant to FERC procedures, on February 1, 1976, August 16, 1979, July 16, 1981, June 2, 1982 and October 9, 1983, increases in the Company's resale rates became effective, subject to refund with interest to the extent that any of the increases are subsequently determined to be inappropriate. Effective May 2, 1974, a Fuel Cost Adjustment Clause (FCA) was added to the Company's resale rates and has been modified concurrent with the subsequent base rate increases beginning with the February 1, 1976 increase. As of December 31, 1983, revenues subject to refund, after giving effect to incremental FCA billing credits, aggregated approximately $383,000,000. The Company believes that, based on present facts, the amount of refunds, if any, likely to result from the outstanding proceedings would not have a material effect on net income.

Legal Matters—
In March 1978, five resale customers filed a suit against the Company in federal court alleging violation of certain antitrust laws. The complaint seeks monetary damages, a trebling of such damages and certain injunctive relief. The complaint alleges that the Company (i) is engaging in anticompetitive behavior by charging more for wholesale electricity sold to the resale customers than the Company charges certain classes of its retail customers ("price squeeze"), and (ii) has taken action alone and in concert with other utilities to prevent or limit such resale customers from obtaining bulk power supplies from other sources to reduce or replace the resale customers' wholesale purchases from the Company ("foreclosure"). The plaintiffs have estimated their actual damages for alleged price squeeze before trebling at approximately $22,700,000; alleged foreclosure damages before trebling at approximately $37,900,000 through July 31, 1982; and have projected damages before trebling for the period August 1, 1982 to July 31, 1985 ranging from approximately $12,100,000 to $33,700,000. It is estimated that the trial will begin sometime in late 1984. The foregoing proceedings involve complex issues of law and fact and, although the Company is unable to predict their final outcome, it has categorically denied the allegations of these resale customers.

Note 3—Leases

Rental payments charged to operating expenses amounted to $61,714,000, $39,542,000 and $39,087,000 for 1983, 1982 and 1981, respectively.

The Company leases nuclear fuel to meet its energy requirements. Under the terms of the lease agreement, quarterly payments are based upon consumption of the nuclear fuel and are designed to return to the lessor the accumulated investment in nuclear fuel and a financing charge on unrecovered costs. Such quarterly payments are recoverable through the Company's ECAC procedures.

The nuclear fuel lease and certain other leased property would meet the criteria requiring capitalization under generally accepted accounting principles. However, since these leases are treated as operating leases for ratemaking purposes, they have been accounted for in the same manner. If such leases had been capitalized, related assets and liabilities of approximately $533,900,000 and $489,600,000 would have been recorded at December 31, 1983 and December 31, 1982, respectively. The difference between imputed interest expense and depreciation for these capital lease properties and actual recorded lease expense is not material.

At December 31, 1983, estimated rental commitments for unrecorded capital leases and noncancelable operating leases consisted of the following:

	Thousands of Dollars	
Year Ended December 31	Capital Leases (a)	Operating Leases
1984	$ 7,503	$24,729
1985	4,774	13,020
1986	2,764	10,708
1987	789	8,790
1988	172	7,029
For periods thereafter	4,301	13,274
Total future rental commitments (b)	20,303	$77,550
Less amount representing interest	(2,418)	
Present value of future minimum rental commitments	$17,885	

(a) Excludes nuclear fuel, the cost base of which is payable when the fuel is consumed. The unrecovered cost base of the nuclear fuel lease was approximately $516,000,000 at December 31, 1983.

(b) As a result of amendments to certain leases during 1983, lease commitments in the amount of $52,775,000 as of December 31, 1983 have been reclassified from capital leases to operating leases.

Note 4—Short-term Borrowings

In order to continue lines of credit with various banks, the Company presently maintains deposits aggregating approximately $12,000,000 which are not legally restricted as to withdrawal. The lines of credit, which are also available to support commercial paper, amounted to $552,000,000 as of December 31, 1983 and December 31, 1982. In addition, the Company also has lines of credit totaling $10,000,000 as of December 31, 1983 and $35,000,000 as of December 31, 1982, which may be utilized for general corporate purposes.

The Company has an additional $150,000,000 line of credit which may be utilized only for the purchase of fuel oil through the use of bankers' acceptances. Notes issued under this agreement are secured by a pledge of the Company's fuel oil inventory.

The Company has guaranteed commercial paper (included on the Company's balance sheet) issued by its wholly-owned subsidiary engaged in financings. Proceeds from the issuance of the commercial paper are used for capitalization of an affiliate engaged in Eurodebenture borrowings. The lines of credit available for the issuance of commercial paper amounted to $150,000,000 at December 31, 1983 and $103,600,000 at December 31, 1982. Commercial paper issued in excess of the subsidiary's lines is supported by the Company's lines of credit.

Notes to Financial Statements (Continued)

Short-term borrowings and the weighted average interest rates for the balances outstanding were as follows:

	Short-term Borrowings (Thousands of Dollars)		Weighted Average Interest Rate	
	December 31,		December 31,	
	1983	1982	1983	1982
Southern California Edison Co.:				
Notes payable to banks	$ 6,006	$ 23,992	9.6%	8.9%
Pollution control loan payable	50,000	—	6.6%	—
Securities held by a trustee	(12,336)	—		
Total	$ 43,670	$ 23,992		
Financing Subsidiary:				
Notes payable to banks	$ —	$ 18,600	—	16.1%
Commercial paper payable	154,300	104,700	9.5%	8.7%
Total	$154,300	$123,300		

Note 5—Income Taxes

Deferred income taxes are provided for certain net increases or decreases in income tax expense which result from reporting certain transactions for income tax purposes in a period different from that in which they are reported in the financial statements. The major items for which deferred income taxes are provided are the tax effects of regulatory balancing account provisions, depreciation related to plant additions after December 31, 1980 (Accelerated Cost Recovery System (ACRS) property), and resale revenues. In accordance with CPUC requirements, deferred income taxes are not provided for other differences.

As of January 1, 1983, the Company has been providing deferred income taxes for ACRS property under provisions of the Economic Recovery Tax Act of 1981 (ERTA) and pursuant to CPUC requirements. The amount of deferred taxes is based upon the difference between tax depreciation and depreciation of tax basis using book methods and lives. The deferred tax provisions also applied, in part, in 1982 under transitional rules, but were not applicable to 1981.

Under provisions of ERTA, all Investment Tax Credits (ITC) generated after 1982 are being deferred and amortized as reductions to income tax expense ratably over the lives of the property giving rise to the credits. Prior to 1983, the Company only deferred the additional ITC permitted by the Tax Reduction Act of 1975 and the Tax Reform Act of 1976. That portion of ITC available under prior law was applied as a current reduction of income tax.

Interpretive regulations are yet to be issued with respect to certain provisions of the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA) which have an impact on the Company. Major provisions affecting the Company include (i) the current deductibility of interest and property taxes incurred during construction of real property and (ii) a requirement to reduce tax basis for one-half of the ITC utilized after 1982, or to reduce the amount of ITC from 10% of an asset's cost to 8%. Net income reflects the Company's estimate of the impact of the TEFRA provisions. It is believed interpretive regulations will not substantially change the impact already reflected.

The current and deferred components of income tax expense are as follows:

	Thousands of Dollars		
	Year Ended December 31,		
	1983	1982	1981
Current:			
Federal	$ 178,246	$ 140,350	$ 44,800
State	58,655	55,621	25,629
	236,901	195,971	70,429
Deferred—Federal and State:			
Investment tax credits—net	69,416	64,612	47,386
Accelerated cost recovery system property	131,233	51,673	—
Regulatory balancing accounts	(3,919)	(192,726)	26,548
Other	(53,555)	(42,934)	(759)
	143,175	(119,375)	73,175
Total income tax expense	$ 380,076	$ 76,596	$ 143,604
Income taxes included in operating expenses	$ 497,236	$ 177,251	$ 197,865
Income taxes included in other income	(117,160)	(100,655)	(54,261)
Total income tax expense	$ 380,076	$ 76,596	$ 143,604

Total income tax expense differed from the amount computed by applying the Federal statutory tax rate of 46% to income before income taxes for the following reasons:

	Thousands of dollars		
	Year Ended December 31,		
	1983	1982	1981
Expected federal income tax expense at statutory rate	$ 492,594	$ 290,861	$ 291,398
Increase (Decrease) in income tax expense resulting from:			
Allowance for equity and borrowed funds used during construction	(168,294)	(139,434)	(106,974)
Federal deduction for state taxes on income	(24,712)	(5,518)	(14,253)
Depreciation timing differences not deferred	45,732	(33)	10,176
Investment tax credits—net	(7,174)	(31,502)	(27,232)
Administrative and general expenses capitalized	(16,626)	(13,449)	(9,756)
Nuclear fuel lease interest capitalized	(3,940)	(20,555)	(18,917)
Taxes capitalized	(10,273)	(20,721)	(14,877)
State tax provision	53,723	11,997	30,985
All other differences	19,046	4,950	3,054
Total income tax expense	$ 380,076	$ 76,596	$ 143,604
Pretax income	$1,070,856	$ 632,350	$ 633,516
Effective tax rate (Total income tax expense ÷ Pretax income)	35.5%	12.1%	22.7%

Note 6—Research and Development

Research and Development (R&D) costs are expensed currently if they are of a general nature. Plant-related R&D costs are accumulated in construction work in progress until a determination is made as to whether such projects will result in construction of electric plant. If no construction of electric plant ultimately results, the costs are generally charged to Other Operation Expenses.

	Thousands of Dollars		
	Year Ended December 31,		
	1983	1982	1981
R&D costs charged to expense	$32,588	$25,998	$26,542
R&D costs capitalized—net	11,687	24,218	32,047
Total R&D expenditures	$44,275	$50,216	$58,589

Note 7—Employee Benefit Plans

Pension Plan—
The Company's current pension program, which covers substantially all employees, is based on a trusteed pension plan, which is non-contributory by employees. The annual normal cost of the plan is funded by the Company with contributions determined on the basis of a level premium funding method. Unfunded prior service costs relating to a 1982 plan amendment are being amortized over a 30-year period. Pension costs are reserved for on the basis of actuarial determinations and amounted to $48,701,000, $42,079,000 and $36,137,000 for 1983, 1982 and 1981, respectively.

	Thousands of Dollars	
	January 1,	
	1983 (a)	1982
Actuarial present value of accumulated plan benefits:		
Vested	$515,134	$449,580
Nonvested	25,357	22,123
	$540,491	$471,703
Net assets available for plan benefits	$624,917	$507,966

(a) Latest available data.

An actuarial rate of return assumption of 6.5% was used in determining the actuarial present value of accumulated plan benefits as of January 1, 1983 and January 1, 1982.

Stock Savings Plus Plan—
The Stock Savings Plus Plan (SSPP), adopted to supplement employees' income after retirement, became effective on January 1, 1984. The SSPP allows eligible employees to contribute up to 11% of their regular monthly base pay, using before-income-tax dollars, to a trustee for the purchase of Company Common Stock. The Company contributes to the SSPP an amount equal to one-half of the first 6% of the employees' contributions, less forfeitures. Participants who have attained age 50 may allocate their contributions into various investment programs. The SSPP replaced the Employee Stock Purchase Plan (ESPP), which was in effect through December 31, 1983 and utilized employee contributions consisting of after-income-tax dollars. The Company's contributions to the ESPP amounted to $5,639,000, $4,687,000 and $4,452,000 for 1983, 1982 and 1981, respectively.

Employee Stock Ownership Plan—
The Company has an Employee Stock Ownership Plan (ESOP) through which, prior to 1983, the Company was allowed to claim additional 1% and ½% ITC with employees matching the ½% ITC. Under provisions of ERTA, the method of funding employee stock ownership plans was changed effective January 1, 1983 from the method based upon ITC's to a payroll tax credit method based upon a specified percentage of total Company payroll. Funding through these payroll based credits may not exceed ½% of total payroll for 1983 and 1984, ¾% for 1985–1987, and is eliminated after 1987. There will be no employee contributions to the Plan.

Note 8—Quarterly Financial Data

The following table presents quarterly financial data for the four quarters of the years 1983, 1982 and 1981:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
1983				
Operating Revenues (000)	$1,040,773	$1,045,247	$1,248,670	$1,129,566
Operating Income (000)	161,636	161,440	171,271	209,683
Net Income (000)	168,948	172,576	192,077	157,179
Earnings Available for Common and Original Preferred Stock (000)	150,538	154,176	173,735	138,854
Earnings Per Share	1.54	1.56	1.74	1.38
1982				
Operating Revenues (000)	1,129,236	1,047,426	1,110,617	1,015,323
Operating Income (000)	111,451	120,636	169,066	135,574
Net Income (000)	124,691	126,786	166,858	137,419
Earnings Available for Common and Original Preferred Stock (000)	107,765	108,338	148,250	119,004
Earnings Per Share	1.18	1.15	1.55	1.23
1981				
Operating Revenues (000)	908,514	983,848	1,122,674	1,039,320
Operating Income (000)	105,724	121,409	150,996	113,026
Net Income (000)	100,167	113,939	147,944	127,862
Earnings Available for Common and Original Preferred Stock (000)	83,158	96,965	130,985	110,917
Earnings Per Share	1.00	1.13	1.51	1.27

Notes to Financial Statements (Continued)

Note 9—Jointly-Owned Utility Projects

The Company owns undivided interests in several jointly-owned generating stations and transmission systems for which each participant must provide its own financing. The Company's proportionate share of expenses pertaining to such projects is included in the appropriate category of operating expenses in the Statements of Income. In the table below, the amounts represent the Company's investment for each such project as reported on the Balance Sheets:

	Thousands of Dollars			
	December 31, 1983			
Projects	Utility Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership Interest
Brawley Geothermal Generating Project	$ 6,307	$ 4,099	$ 184	50.0%
El Dorado Transmission System	21,046	6,192	66	60.0(a)
Four Corners Coal Generating Station—Units 4 & 5	204,470	42,633	118,281	48.0
Mohave Coal Generating Station	196,386	58,738	3,467	56.0
Pacific Intertie DC Transmission System	69,475	22,661	14,447	50.0
Palo Verde Nuclear Generating Station	906	2	935,678	15.8
San Onofre Nuclear Generating Station—				
Unit 1	242,383	72,815	121,974	80.0
Units 2 & 3	1,445,070	20,348	1,382,466	75.05
Common Facilities—Units 2 & 3	380,950	5,645	2,369	75.05
Common Facilities—Units 1, 2, & 3	76,276	5,111	33,487	75.87
Solar One Generating Station	17,660	5,522	513	80.0
Yuma Axis Combined Cycle Generating Station	12,354	8,026	17	33.3
Total	$2,673,283	$251,792	$2,612,949	

(a) Represents a composite rate.

Unit 1 at San Onofre has been out of service since February 1982 for NRC required inspections and for various plant modifications. The return to service date of Unit 1 is currently under evaluation and is chiefly contingent on reaching an agreement with the NRC on specific seismic modifications to prove earthquake resistance and other long-range NRC requirements. Because of this extended outage, the CPUC recently began an investigation to determine whether Unit 1 should be removed from customer rates while the plant modification issues are being resolved with the NRC. A recently filed CPUC staff motion in this proceeding, if adopted by the Commission, would remove the Unit 1 return component from customer rates, but permit the accrual of an Allowance for Funds Used During Construction. As indicated in its response to the CPUC investigation, the Company believes that Unit 1 should remain in customer rates. Commencing January 1, 1984, all rates authorized for Unit 1 operation and ownership costs are being collected subject to refund pending completion of the CPUC's investigation. As of December 31, 1983, the Company's undepreciated book cost, including nuclear fuel, for this Unit was $327,900,000 excluding the provision for decommissioning costs.

Note 10—Long-term Purchased Power and Transmission Contracts

Under firm contracts, the Company has agreed to purchase portions of the generating output of certain facilities and to purchase firm transmission service where appropriate. Although the Company has no investment in such facilties, these contracts provide that the Company pay certain minimum amounts (which are based at least in part on the debt service requirements of the supplier) whether or not the facility or transmission line is operating. None of these power contracts provides, or is expected to provide, in excess of five percent of the Company's current or estimated future operating capacity. The cost of power and firm transmission service obtained under the contracts, including payments made when a facility or transmission line is not operating, is included in Purchased Power and Other Operation Expenses, respectively, in the Statements of Income. Purchased power costs are recoverable through the Company's ECAC procedure. Certain information as of December 31, 1983, pertaining to purchased power contracts is summarized in the following table:

	Dollars in Thousands
Share of Effective Operating Capacity—Megawatts (MW) (a)	718.5
Share of Energy Output	7.9%–14.6%
Total Estimated Annual Cost	$46,956
Company's Portion of Estimated Annual Cost Applicable to Supplier's Annual Minimum Debt Service Requirement	$ 5,326
Company's Allocable Portion of Interest of Suppliers included in Annual Minimum Debt Service Requirement	$ 3,465
Related Long-term Debt or Lease Obligations Outstanding of Company	None

(a) Effective operating capacity may vary according to water availability and other conditions. The Company has agreed to certain reductions in its share of operating capacity prior to the expiration date of a certain contract.

Additional information as of December 31, 1983 pertaining to both purchased power and transmission service contracts is summarized in the following table:

	Dollars in Thousands	
	Purchased Power	Transmission Service
Dates of Expiration	1984–1987	1984–2016
Variable Components of Contracts	(a)	(a)
Required Future Minimum Annual Payments		
1984	$ 9,593	$ 7,000
1985	1,560	5,920
1986	1,644	5,905
1987	723	5,890
1988	—	5,875
Later years	—	155,682
Total	13,520	186,272
Less Amount Representing Interest to Reduce Total to Present Value	(461)	(115,649)
Total at Present Value	$ 13,059	$ 70,623
Total Purchases for the Years Ended December 31,		
1983	$ 49,263	$ 7,595
1982	39,414	7,409
1981	36,603	7,658

(a) The variable components of certain contracts are based upon a pro-rata share of actual operating, maintenance, and fuel costs or on the U.S. Government cost of service.

Supplementary Information to Disclose the Effects of Changing Prices (Unaudited)

The Company's primary financial statements are stated on the basis of historical costs in accordance with generally accepted accounting principles. During periods of significant changes in price levels, amounts reported on this basis reflect dollars of varying purchasing power and accordingly do not measure the effects of inflation. The following supplementary information is presented in accordance with the requirements of the Financial Accounting Standards Board (FASB) for the purpose of providing certain information about the effects of both general inflation (represented by constant dollar amounts) and changes in specific prices (represented by current cost amounts).

This information inherently involves the use of assumptions, approximations and estimates, and therefore, should be viewed in that context and not as precise measurements of the effects of inflation on the Company.

Statement of Earnings Available for Common and Original Preferred Stock Adjusted for Changing Prices for the Year Ended December 31, 1983

	Thousands of Dollars		
	As Reported in the Primary Financial Statements	Adjusted For General Inflation (a) (Constant Dollar)	Adjusted For Changes in Specific Prices (a) (Current Cost)
Total Operating Revenues	$4,464,256	$4,464,256	$4,464,256
Operating Expenses:			
Depreciation	289,361	667,000	774,000
Other operating expenses	3,470,864	3,470,864	3,470,864
Other income	(429,101)	(429,101)	(429,101)
Net interest charges	442,352	442,352	442,352
Dividends on cumulative preferred and preference stock	73,477	73,477	73,477
	3,846,953	4,224,592	4,331,592
Earnings available for Common and Original Preferred Stock (excluding adjustment of utility plant to net recoverable cost)	$ 617,303	$ 239,664(b)	$ 132,664
Other Adjustments For Changing Prices:			
Increase in specific prices (current cost) of utility plant held during year (c)			$ 612,563
Adjustment of utility plant to net recoverable cost		$ 42,642	188,764
Effect of increase in general price level on utility plant			(651,685)
Excess of increase in specific prices over increase in general price level, after adjustment to net recoverable cost			$ 149,642
Gain from decline in purchasing power of net amounts owed		$ 201,633	$ 201,633

(a) In average 1983 dollars.

(b) Including the adjustment to net recoverable cost, the earnings available for common and original preferred stock on a constant dollar basis would have been $282,306 for 1983.

(c) At December 31, 1983, current cost of utility plant, net of accumulated depreciation (but exclusive of deferred income taxes) was $18,015,435 while related historical cost and net recoverable cost was $9,460,242.

Supplementary Information (Continued)

Five Year Comparison of Selected Supplementary Financial Data Adjusted for the Effects of Changing Prices

(Data adjusted for the effects of changing prices are reported in average 1983 dollars.)

In Thousands of Dollars, Except Per Share Amounts	Year Ended December 31, 1983	1982	1981	1980	1979
Total Operating Revenues					
As reported	$4,464,256	$4,302,602	$4,054,356	$3,661,117	$2,563,974
In constant 1983 dollars	$4,464,256	$4,441,012	$4,441,336	$4,426,569	$3,519,273
Earnings Available for (Loss on) Common and Original Preferred Stock (a)					
As reported	$ 617,303	$483,358	$422,024	$256,586	$292,481
In constant 1983 dollars	$ 239,664	$204,768	$171,116	$ 46,604	$166,245
At current cost	$ 132,664	$101,037	$ 79,098	$ (52,540)	$ 77,027
Earnings (Loss) Per Share on Common and Original Preferred Stock (a)					
As reported	$6.22	$5.13	$4.93	$3.50	$4.56
In constant 1983 dollars	$2.42	$2.17	$2.00	$ .64	$2.59
At current cost	$1.34	$1.07	$ .92	$ (.72)	$1.20
Excess of Increase in General Price Level Over Increase in Specific Prices of Utility Plant after Adjustment to Net Recoverable Cost	$(149,642)	$ (46,736)	$288,586	$506,241	$681,010
Net Assets at Year End at Net Recoverable Cost					
As reported	$3,793,339	$3,392,864	$2,968,108	$2,529,577	$2,233,133
In constant 1983 dollars and current cost	$3,729,596	$3,438,963	$3,139,607	$2,925,681	$2,898,507
Gain from Decline in Purchasing Power of Net Amounts Owed	$ 201,633	$212,027	$410,365	$537,908	$620,760
Cash Dividends Declared Per Common Share					
As reported	$3.66	$3.38	$3.10	$2.84	$2.60
In constant 1983 dollars	$3.64	$3.48	$3.37	$3.40	$3.52
Market Price Per Share at Year End					
In historical dollars	$39.75	$35.125	$28.75	$25.625	$24.50
In constant 1983 dollars	$39.08	$35.85	$30.41	$29.59	$31.80
Average Consumer Price Index (Base Year 1967 = 100)	298.4	289.1	272.4	246.8	217.4

(a) Excludes adjustment of Utility Plant to Net Recoverable Cost.

The amounts adjusted for general inflation represent historical costs of utility plant restated in terms of dollars of equal purchasing power (constant dollars) as measured by the Consumer Price Index for all Urban Consumers. This method is intended to measure income after restating all revenues and expenses in dollars of equivalent purchasing power.

The current cost amounts reflect the changes in specific prices of utility plant from the date the plant was acquired to the present, and differ from constant dollar amounts to the extent that prices in general have increased more or less rapidly than specific prices. The current cost of utility plant represents the estimated cost of replacing existing plant assets and was determined by restating its historical cost using indices reported in the Handy-Whitman Index of Public Utility Construction Costs. This method is intended to measure income after reflecting the cost of providing the electric service at current price levels.

In accordance with procedures specified by the FASB, total operating revenues and all expenses other than depreciation were considered to reflect the average price level for the current year and accordingly remain unchanged from those amounts reported in the Company's primary financial statements. The current year's depreciation expense on the constant dollar and current cost amounts of utility plant was determined by applying the Company's average annual depreciation rates to the indexed plant amounts.

No adjustments to income tax expense have been made in computing the impact of inflation since only historical costs are deductible for income tax purposes.

Fuel inventories and the cost of fuel consumed in the generation of electricity have not been restated from their historical cost. The recovery of fuel and purchased power costs are limited to historical costs through the operation of the Company's energy cost adjustment clauses. For this reason fuel inventories and deferred recoverable energy costs are effectively monetary assets.

Under ratemaking procedures prescribed by the regulatory commissions exercising rate jurisdiction over the Company, only the historical cost of utility plant is recoverable through future depreciation charges. Therefore, the cost of utility plant, stated in terms of constant dollars or current cost is not presently recoverable through depreciation charges. Accordingly, the difference between such restated plant amounts and historical cost is reflected as an adjustment of utility plant to net recoverable cost. While the ratemaking process gives no recognition to the current cost of replacing utility plant, based on past ratemaking practices, the Company believes it will be allowed to recover and earn a return on the increased cost of its investment when replacements of utility plant occur.

During inflationary periods, holders of monetary assets experience a loss of general purchasing power while holders of monetary liabilities experience a gain. The gain from the decline in purchasing power of net monetary liabilities (net amounts owed) is primarily attributable to the substantial amount of debt which has been used to finance utility plant. To properly reflect the economics of rate regulation, the adjustment of utility plant to net recoverable cost should be offset or combined, as appropriate, by the gain from the decline in purchasing power of the dollar related to net amounts owed, including Cumulative Preferred and Preference Stock. The Company, therefore, does not have the opportunity to realize such holding gain on net amounts owed.

Operating Revenues and Kilowatt-Hour Sales

Class of Service	Operating Revenues (Thousands of Dollars)				Kilowatt-Hour Sales (000)			
	% of 1983 total	1983	1982	% change	% of 1983 total	1983	1982	% change
Residential	28.1	$1,255,700	$1,233,338	1.8	28.7	17,173,786	16,403,116	4.7
Agricultural	1.3	56,649	68,281	(17.0)	1.2	709,094	856,929	(17.3)
Commercial	30.0	1,337,910	1,226,532	9.1	28.0	16,777,503	15,557,692	7.8
Industrial	25.2	1,126,636	1,112,784	1.2	26.1	15,643,149	15,675,707	(0.2)
Public Authorities	8.5	376,782	370,726	1.6	8.2	4,914,422	5,985,313	(17.9)
Interdepartmental	—	109	127	(14.2)	—	994	1,279	22.3
Resale	5.8	259,833	255,162	1.8	7.8	4,673,690	4,846,817	(3.6)
Sales of Electric Energy	98.9	4,413,619	4,266,950	3.4	100.0	59,892,638	59,326,853	1.0
Other Electric Revenues	1.1	50,637	35,652	42.0	—	—	—	
Total	100.0	$4,464,256	$4,302,602	3.8	100.0	59,892,638	59,326,853	1.0

Operating Revenues by Rate Components

Rate Components	Operating Revenues (Thousands of Dollars)			Percent of Total		
	1983	1982	1981	1983	1982	1981
Base Rates—CPUC Jurisdiction	$2,138,011	$1,530,389	$1,487,145	47.9%	35.6%	36.6%
Energy Cost Adjustment Billing Factor	1,789,474	2,312,442	2,161,426	40.1	53.7	53.3
Annual Energy Rate	163,817	167,457	31,704	3.7	3.9	0.8
Major Additions Adjustment Billing Factor	29,651	—	—	0.7	—	—
Other Billing Factors	33,189	1,942	2,767	0.7	0.1	0.1
Resale Rates (excluding fringe)	259,477	254,720	343,506	5.8	5.9	8.5
Sales of Electric Energy	4,413,619	4,266,950	4,026,548	98.9	99.2	99.3
Other Electric Revenues	50,637	35,652	27,808	1.1	0.8	0.7
Total	$4,464,256	$4,302,602	$4,054,356	100.0	100.0	100.0

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

Results of Operations

The Company recorded earnings per share of $6.22 and a rate of return on common equity of 17.0% in 1983, as compared with $5.13 and 14.9%, respectively, in 1982.

Several factors were primarily responsible for the improved earnings level achieved by the Company for the year 1983:

- The general rate increase of $590 million annually which was granted effective January 1, 1983, and which authorized a rate of return on rate base (CPUC jurisdiction) of 12.55% and a rate of return on common equity of 16%.
- A continuing emphasis on productivity and cost controls.
- Higher non-cash allowances for funds used during construction (AFUDC).
- The smallest increases in average number of shares outstanding (5.2%) and average common equity (12%) since 1978. There was no major public offering of common stock in 1983.

In addition to the improvement in the level of earnings during 1983, there was an accompanying improvement in earnings quality. Earnings quality, as measured by the ratio of operating income to total income before interest charges (including allowance for borrowed funds), was 57% for 1983 which compares with 55% for 1982 and was the first time that the ratio has not recorded a year-to-year decrease since 1972. An increase in this ratio is indicative of improvement in earnings quality because the remainder of total income before interest charges comprises AFUDC and other income.

The principal reasons for the improving earnings quality are the aforementioned general rate increase and continuing efforts to control costs and the transfer of the investment in San Onofre Unit 2 from construction to rate base. (For a further discussion of the initial decisions of the CPUC under MAAC, see "Liquidity.") Operation of San Onofre Unit 2 is reflected in the Company's operating revenues and operating expenses commencing October 9, 1983.

Comparing results for 1983 with 1982, operating revenues increased while total operating expenses decreased with the result that operating income was higher by over 31%. In addition, AFUDC and other income were up by 20% while interest charges and preferred dividends increased 28% and 1.5%, respectively, with the end result that earnings available for common and original preferred stock increased by 28%.

The following table presents amounts and percentages of increase (decrease) from the prior years in the rate components of operating revenues.

Increase (Decrease) from Prior Years	Dollars in Millions 1983	%	1982	%	1981	%
Operating Revenues:						
Base Rates (CPUC)	$608	39.7	$ 43	2.9	$284	23.6
Energy Cost Adjustment Billing Factor	(523)	(22.6)	151	7.0	(19)	(0.9)
Annual Energy Rate	(4)	(2.2)	136	(a)	32	—
Major Additions Adjustment Billing Factor	30	—	—	—	—	—
Other Billing Factors	31	(a)	(1)	(29.8)	(2)	(46.1)
Resale	5	1.9	(89)	(25.8)	100	41.5
Other Electric Revenues	15	42.0	8	28.2	(2)	(6.5)
Total Operating Revenues	$162	3.8	$248	6.1	$393	10.7
KWH Sales (Millions)	566	1.0	(3,124)	(5.0)	2,536	4.2
Customers	50,159	1.5	42,457	1.3	68,719	2.2

(a)Indicates over 200%.

The increase in total operating revenues for 1983 reflected the combined effect of an increase of 2.5% in the overall average billing rates and the 1% increase in kilowatt-hour sales. The decrease in energy cost adjustment billing factor revenue reflected reductions in rates because of actual and anticipated decreases in fuel and purchased power expenses.

A more complete description of the procedures used to establish the Company's rate levels for retail sales is included in Note 1 of the "Notes to Financial Statements." In general, base rates are established in biennial general rate case proceedings before the CPUC. In addition, regulatory adjustment clauses which remove the effect on earnings of fluctuations in fuel and purchased power expenses, kilowatt-sales and certain conservation program expenses have been authorized by the CPUC. A Major Additions Adjustment Clause was established to include in retail rates the cost of owning and operating San Onofre Unit 2.

The following table presents amounts and percentages of increase (decrease) from prior years in selected items from the Statements of Income.

Increase (Decrease) from Prior Years	Dollars in Millions, Except Earnings Per Share 1983	%	1982	%	1981	%
Other Operation Expenses	$113	23.0	$50	11.4	$49	12.6
Maintenance Expense	70	33.2	17	8.7	(35)	(15.3)
Depreciation	68	31.0	19	9.3	14	7.6
Taxes on Operating Income	320	180.5	(21)	(10.4)	159	(a)
Property & Other Taxes	17	26.5	6	9.4	(10)	(14.0)
Operating Income	167	31.2	46	9.3	119	32.0
Allowance for Equity and Borrowed Funds Used During Construction	63	20.7	71	30.3	70	43.3
Other Income	24	17.7	29	27.1	41	63.0
Total Interest Charges	119	28.3	79	23.3	58	20.6
Net Income	135	24.3	66	13.4	172	54.3
Earnings Available for Common and Original Preferred Stock	134	27.7	61	14.5	165	64.5
Earnings Per Share	$1.09	21.2	$.20	4.1	$1.43	40.9
Weighted Average Number of Shares (Millions)	5	5.2	9	10.1	12	16.9

(a)Indicates over 200%.

Increases in other operation expenses in 1983 continued to be influenced by system growth, particularly the addition of San Onofre Unit 2. Also having an impact is the effect of inflation on the cost of labor, material and services. The Company is continuing its efforts to control these expenses.

Variations in levels of maintenance expense have been significantly influenced by inflation, scheduling of major maintenance projects, the addition of new facilities, and weather conditions. The latter is partially reflected in increases in property damage expense as a result of storm damage of $6 million. Also affecting maintenance expense in 1983 is the amortization of nuclear sleeving costs of $14 million.

Taxes on operating income for 1983 increased primarily as a result of increased pre-tax net income and deferred income tax provisions. For a further discussion of income taxes see Note 5 of "Notes to Financial Statements."

The higher interest charges were primarily due to additional long-term debt outstanding the entire year.

A discussion relating to the effects of changing prices follows the "Notes to Financial Statements" beginning on page 39.

Liquidity

Liquidity refers to the ability of a company to generate funds, whether from operations, long-term financing or other sources, adequate to meet the requirements of its construction program.

The improvement during 1983 in the Company's earnings quality is further demonstrated by the increase in funds provided by operations as a percent of funds used for construction expenditures from 24% for 1982 to 48% in 1983.

The following table provides a summary of the Company's sources of funds used for construction expenditures for the years 1983, 1982 and 1981.

	Dollars in Millions 1983	1982	1981
Funds from Operations—Reinvested	$390	$243	$174
Funds from Long-Term Financing—Net	215	828	800
Other Sources (Uses) of Funds	200	(77)	(17)
Funds Used for Construction Expenditures	$805	$994	$957
Funds Provided by Operations as a Percent of Funds Used for Construction Expenditures	48%	24%	18%

The Company is engaged in an extensive construction program designed to accommodate existing and projected demands on its electric system. Because of the high level of construction work in progress, primarily related to the construction of San Onofre Unit 2 (now complete) and Unit 3 and the Palo Verde Units, a significant portion of the Company's net income in recent years has been attributable to AFUDC, which does not represent current cash income of the Company. On September 7, 1983, the CPUC rendered an initial decision under the Major Additions Adjustment Clause (MAAC) to include in customer rates the costs of owning and operating Unit 2 at San Onofre. The new rates became effective October 9, 1983 when approximately $1.6 billion of plant investment costs were included in rate base. The accrual of AFUDC on these costs ceased as of that date. The amount of the initial MAAC rate increase was $207 million; however, this was offset by an equal Energy Cost Adjustment Clause rate decrease based on projected fuel savings.

Management's Discussion and Analysis (Continued)

In its September 7, 1983 MAAC Decision, the CPUC directed the Company and the Commission staff to undertake studies to determine if various alternative ratemaking methods should be adopted in establishing retail rates for San Onofre Units 2 and 3. As compared to traditional ratemaking practices, the adoption of an alternative ratemaking method would produce lower cash flow in the early years of operation and higher cash flow in later years. The Company believes that the placement of San Onofre Units 2 and 3 in service with rates established in accordance with traditional procedures will not produce a dramatic increase in rates and that adoption of an alternative ratemaking method is unwarranted. Hearings on this matter are expected to commence during the second quarter of 1984 with a decision to be rendered soon thereafter.

On November 22, 1983, the CPUC issued a second decision granting an additional $98 million of rate relief for Unit 2 to become effective January 1, 1984. The Company, therefore, will receive additional cash income to partially offset the decline in AFUDC. Earnings will be maintained by the return on rate base authorized by the MAAC decision and by the implementation of an interest-bearing balancing account for the facility's investment-related costs. Recoverability of amounts recorded in the balancing account will be determined in the CPUC's reasonableness review for the Company's investment in Unit 2. AFUDC constituted approximately 53%, 55% and 47% of net income, respectively, for the years 1983, 1982 and 1981. AFUDC is expected to decline significantly with the inclusion of Unit 2 in rates and when Unit 3 is placed in commercial operation, which is currently anticipated to be in April of 1984.

San Onofre Unit 1 has been out of service since February 1982 for NRC required inspections and for various plant modifications. See Note 9 of "Notes to Financial Statements" for a discussion of the CPUC's investigation to determine whether Unit 1 should be removed from customer rates while plant modification issues are being resolved with the NRC. A recently filed CPUC staff motion in this proceeding, if adopted by the Commission, would remove the San Onofre Unit 1 return component from customer rates, but permit the accrual of an Allowance for Funds Used During Construction.

Capital Resources

To provide the funds for construction expenditures for the five years through 1988, estimated to total $4.0 billion, and to meet long-term debt maturities and sinking fund requirements and preferred stock redemption requirements aggregating $726 million during such years, the Company estimates that approximately $2.4 billion, or 50%, of such expenditures will be provided from external sources. The balance of funds required for these purposes is expected to be obtained from operations, primarily during the latter part of such period.

The Company's estimates of funds available from operations for the five years through 1988 assume the receipt of adequate and timely rate relief, the timely inclusion of San Onofre Unit 3 and the Palo Verde Units in rate base and the realization of its assumptions regarding cost increases, including the cost of capital. The Company's estimates and underlying assumptions are subject to continuous review and periodic revision.

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

The Company's long-term goal is to maintain a capital structure with approximately equal amounts of debt and equity. The Company's capital structure at the end of the years 1983, 1982 and 1981 is shown below:

	1983	1982	1981
Common Shareholders' Equity	43.3%	41.0%	40.7%
Preferred and Preference Stock Without Mandatory Redemption Requirements	5.4	5.7	6.5
Preferred and Preference Stock With Mandatory Redemption Requirements (a)	5.0	5.4	5.5
Long-Term Debt (a)	46.3	47.9	47.3
	100.0%	100.0%	100.0%

(a) Excludes current portion.

Funds provided by long-term financing, after giving effect to the reduction of long-term debt, securities held by trustees and the conversion of preference stock amounted to $215 million in 1983. The Company uses short-term borrowings and temporary investments as a part of normal daily operations. The Company has a total of $862 million of available short-term borrowing facilities with foreign and domestic banks. Temporary investments and cash investments—financing subsidiary, outstanding at December 31, 1983 were $244 million and $157 million, respectively.

Capital Stock—Dividend and Price Information

Class and Series of Stock	Quarterly Dividends Paid Per Share (a) (f)	High and Low Sales Prices ($)															
		Calendar Quarter—1983								Calendar Quarter—1982							
		1		2		3		4		1		2		3		4	
		High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
Common (b)(c)	$ .88	39¼	34⅝	38⅛	34⅜	39⅛	35⅛	42¾	37⅝	32½	28	33⅝	29⅞	35⅞	29½	37⅛	31¼
Original Preferred	.88	38¾	32	37½	33½	37½	33	39¼	35	29⅜	24½	29¼	25½	31	25¾	34½	30½
Cumulative Preferred:																	
4.08%	.25½	9⅜	8¼	9¾	8¼	9¼	8	9⅜	8⅛	8¼	6⅝	7¾	6⅞	8½	7	9¼	7¾
4.24%	.26½	9⅞	8⅞	10	8¾	9⅝	8⅜	9⅝	8¼	8¼	6½	8	7⅛	9⅛	7¼	9⅜	8⅜
4.32%	.27	9⅞	9	10	9	9⅝	8⅝	9⅝	8⅝	8⅛	7	8⅜	7	9¼	7¼	9⅝	8⅛
4.78%	.29⅞	11⅜	9½	11⅞	9⅞	10¾	9	10¾	9¼	8⅝	7½	9	7¼	9¾	7¾	10⅞	9
5.80%	.36¼	13¾	12	13½	11¾	13⅜	11⅜	13¼	11¼	10⅝	9¼	10¾	9½	13	9⅞	12⅞	11½
8.85%	.553125	20¾	18¼	20½	18¼	19⅝	18	19⅜	17⅜	16	14⅛	16⅝	14½	18¼	14¾	19½	16⅞
9.20%	.57½	21	19⅜	21⅜	19	20	18⅝	20¼	18¼	16⅜	14½	17⅛	15¼	19	15⅜	20¼	17⅝
$100 Cumulative Preferred:																	
7.325% (d)	1.83⅛	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
7.58%	1.89½	69¼	60	70½	64	67½	60½	68	60	54½	47¾	56⅛	49⅜	60⅝	50½	66⅝	57
7.80% (d)	1.95	—	—	—	—	—	—	—		—	—	—	—	—	—	—	—
8.54%	2.13½	85¼	81	88½	82	82	79	85	73	63¾	59	70¼	62¾	73	69	83½	68
8.70%	2.17½	78	70	80⅞	73	80	70	75	68	62	55½	64	57¼	68⅝	58	76	65½
8.70%-A (d)	2.17½	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
8.96%	2.24	82¼	73	82½	75	78¼	71	77	69⅜	61⅛	56¾	64½	60	71½	60⅜	78	68½
12.00%	3.00	109	103	109	101	106	98½	107⅝	100	89	81½	100	90	102	89¾	106⅛	99
12.31% (d)	3.0775	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Preference:																	
5.20% (e)	.32½	30¾	27⅜	30	28½	30½	27	32⅛	29½	25½	22⅜	26⅜	24¼	28	23½	29	25½
7.375% (d)	.460938	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

(a) Quarterly dividends were paid at the rates indicated in each quarter of 1983 except the fourth quarter dividend on Original Preferred Stock and Common Stock which was at the rate of $0.95 per share.

(b) Dividends per share declared on Common Stock totaled $3.66 and $3.38 for 1983 and 1982, respectively.

(c) As of December 31, 1983, there were approximately 158,000 Common Stock shareholders.

(d) There are no prices as these issues are private placements and shares are not traded.

(e) The 5.20% Preference Stock is convertible into Common Stock.

(f) The Indenture securing the Company's First and Refunding Mortgage Bonds provides, in substance, that the Company shall not pay any cash dividends except out of its earnings reinvested in the business and net income.

Selected Financial Data 1973–1983

		1983	1982
Summary of Operations *(in thousands of dollars except percent and per share data)*	Operating Revenues	$ 4,464,256	$ 4,302,602
	Operating Expenses	3,760,225	3,765,875
	Fuel and Purchased Power Costs (a)	2,027,756	2,227,901
	Income Taxes (a)	497,236	177,251
	Allowance for Equity and Borrowed Funds Used During Construction	365,856	303,118
	Interest Charges	539,377	420,282
	Net Income	690,780	555,754
	Earnings Available for Common and Original Preferred Stock	$ 617,303	$ 483,358
	Weighted Average Shares of Common and Original Preferred Stock Outstanding (000)	99,174	94,257
	Per Share Data:		
	Primary Earnings	$6.22	$5.13
	Fully Diluted Earnings	$6.15	$5.09
	Dividends Declared Per Common Share	$3.66	$3.38
	Dividend Payout Ratio (paid basis)	57.7%	64.5%
	Rate of Return on Common Equity	17.0%	14.9%
	Ratio of Earnings to Fixed Charges	2.91	2.44
Balance Sheet Data *(in thousands of dollars except percent and per share data)*	Total Assets (b)	$11,035,060	$10,157,564
	Gross Utility Plant	11,886,610	10,764,078
	Accumulated Depreciation	$ 2,426,368	$ 2,185,667
	Percent of Gross Utility Plant	20.4%	20.3%
	Common Stock, at par value	$ 839,501	$ 805,766
	Additional Paid-in Capital	1,307,546	1,193,318
	Earnings Reinvested in the Business	1,646,292	1,393,780
	Common Shareholders' Equity	3,793,339	3,392,864
	Preferred and Preference Stock without mandatory redemption requirements	469,025	471,020
	Preferred and Preference Stock with mandatory redemption requirements (c)	440,500	445,000
	Long-term Debt (c)	$4,051,836	$3,970,400
	Capital Structure (percent):		
	Common Shareholders' Equity	43.3%	41.0%
	Preferred & Preference Stock without mandatory redemption requrements	5.4	5.7
	Preferred and Preference Stock with mandatory redemption requirements (c)	5.0	5.4
	Long-term Debt (c)	46.3%	47.9%
	Book Value Per Common Share	$37.52	$34.96
Operating and Sales Data	Area Peak Demand (MW)	13,464	13,149
	Area Generating Capacity at Peak (MW) (d)	16,365	15,349
	Total Energy Requirement (KWH) (000)	68,020,197	66,578,540
	Percent Energy Requirement:		
	Thermal	48.7%	55.5%
	Alternative/Renewable (including hydro)	10.3	9.7
	Purchased Power & Other Sources (e)	41.0%	34.8%
	Kilowatt-Hour Sales (000)	59,892,638	59,326,853
	Average Annual KWH Sales Per Residential Customer	5,879	5,685
	Number of Customers	3,325,303	3,275,144
	Number of Employees	16,292	15,797

(a) Included in Operating Expenses.

(b) The years 1973 through 1981 have been restated to reflect the deduction of property-related accumulated deferred income taxes from Utility Plant.

(c) Excludes current portion.

1981	1980	1979	1978	1977	1976	1975	1974	1973
$4,054,356	$3,661,117	$2,563,974	$2,328,798	$2,064,914	$1,846,540	$1,647,134	$1,360,959	$1,075,949
3,563,201	3,288,983	2,178,978	2,004,197	1,734,192	1,539,400	1,380,528	1,108,249	843,530
2,558,206	2,010,227	1,532,903	1,204,749	1,189,597	903,447	824,826	541,890	344,990
197,865	38,683	100,292	72,803	68,792	59,506	46,623	70,618	46,496
232,552	162,287	118,566	78,421	60,238	47,610	26,773	16,163	10,190
340,977	282,656	205,082	182,658	161,078	144,368	126,185	112,959	97,728
489,912	317,536	346,219	251,683	251,979	226,798	176,781	160,344	146,110
$ 422,024	$ 256,586	$ 292,481	$ 202,226	$ 206,330	$ 185,047	$ 137,177	$ 124,656	$ 117,268
85,610	73,241	64,202	57,477	54,347	48,678	47,965	44,580	43,965
$4.93	$3.50	$4.56	$3.52	$3.80	$3.80	$2.86	$2.80	$2.67
$4.91	$3.48	$4.39	$3.38	$3.63	$3.61	$2.75	$2.68	$2.57
$3.10	$2.84	$2.60	$2.30	$2.06	$1.68	$1.68	$1.68	$1.56
61.5%	79.4%	55.7%	63.6%	50.5%	44.2%	58.7%	58.9%	58.4%
14.9%	10.4%	13.6%	10.7%	12.0%	12.4%	9.8%	9.4%	9.6%
2.72	2.09	2.90	2.53	2.78	2.83	2.63	2.87	2.85
$8,702,571	$7,706,933	$6,949,917	$6,030,045	$5,698,068	$4,993,330	$4,701,910	$4,451,810	$3,861,572
9,517,670	8,406,309	7,577,670	6,810,891	6,191,733	5,658,433	5,147,333	4,766,175	4,458,631
$2,015,212	$1,840,233	$1,676,148	$1,519,174	$1,383,009	$1,258,327	$1,149,311	$1,051,024	$ 958,210
21.2%	21.9%	22.1%	22.3%	22.3%	22.2%	22.3%	22.1%	21.5%
$ 730,027	$ 632,115	$ 540,791	$ 521,138	$ 455,387	$ 442,739	$ 395,707	$ 395,707	$ 362,374
999,764	805,325	638,046	595,701	458,096	427,424	350,505	350,505	316,638
1,238,317	1,092,137	1,054,296	931,217	862,956	769,425	671,548	616,562	569,938
2,968,108	2,529,577	2,233,133	2,048,056	1,776,439	1,639,588	1,417,760	1,362,774	1,248,950
476,308	482,652	489,822	503,650	518,172	537,753	537,753	487,753	437,753
399,500	399,500	324,500	197,000	197,000	75,000	75,000	75,000	75,000
$3,444,080	$2,945,824	$2,746,207	$2,477,474	$2,314,874	$2,151,861	$2,033,038	$1,953,679	$1,722,710
40.7%	39.8%	38.5%	39.2%	37.0%	37.2%	34.9%	35.1%	35.8%
6.5	7.6	8.5	9.6	10.8	12.2	13.2	12.6	12.6
5.5	6.3	5.6	3.8	4.1	1.7	1.9	1.9	2.2
47.3%	46.3%	47.4%	47.4%	48.1%	48.9%	50.0%	50.4%	49.4%
$33.74	$33.19	$34.22	$32.57	$32.30	$30.67	$29.64	$28.50	$28.46
13,738	12,841	12,662	12,159	11,564	11,292	10,369	10,279	10,535
15,592	15,504	15,071	14,966	14,278	14,071	13,941	13,750	13,500
69,179,641	65,459,278	66,216,910	63,877,116	63,344,706	59,427,973	56,279,231	55,105,988	57,730,121
67.6%	71.2%	82.0%	73.8%	87.4%	75.1%	76.2%	75.2%	84.8%
5.8	9.2	7.7	9.3	2.5	4.4	8.4	10.1	9.1
26.6%	19.6%	10.3%	16.9%	10.1%	20.5%	15.4%	14.7%	6.1%
62,451,319	59,915,187	59,517,861	57,027,035	57,726,273	53,685,378	51,327,508	51,089,981	54,092,934
5,879	5,939	6,010	5,883	5,630	5,650	5,596	5,541	5,885
3,232,687	3,163,968	3,082,382	2,986,545	2,900,856	2,814,403	2,749,680	2,691,691	2,626,492
14,569	14,157	12,917	12,845	12,671	12,510	12,377	12,970	13,391

(d) Includes 2,334, 2,080 and 2,323 MW available from others in 1983, 1982 and 1981, respectively.

(e) Includes non-Edison owned renewable/alternative sources.

Directors and Officers

Board of Directors

William R. Gould,
Chairman of the Board and Chief Executive Officer

Howard P. Allen,
President

Roy A. Anderson,
Chairman of the Board and Chief Executive Officer,
Lockheed Corporation, Burbank, California

N. Barker, Jr.,
Chairman of the Board and Chief Executive Officer, First Interstate Bank of California,
and Vice Chairman of the Board, First Interstate Bancorp, Los Angeles, California

(1)Edward W. Carter,
Chairman of the Board Emeritus, Carter Hawley Hale Stores, Inc., Los Angeles, California

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

Walter B. Gerken,
Chairman of the Board and Chief Executive Officer, Pacific Mutual Life Insurance Company,
Newport Beach, California

Joan C. Hanley,
General Partner and Manager, Miramonte Vineyards, Rancho California, California

J. K. Horton,
Chairman of the Executive Committee and Consultant
(Retired Chairman of the Board and Chief Executive Officer,
Southern California Edison Company), Los Angeles, California

Carl F. Huntsinger,
President and Chief Executive Officer, Blue Goose Growers, Inc., Ojai, California

F. G. Larkin, Jr.,
Chairman of the Executive Committee, Security Pacific National Bank, Los Angeles, California

T. M. McDaniel, Jr.,
Former President, Southern California Edison Company, San Marino, California

Gerald H. Phipps,
President, Gerald H. Phipps, Inc., General Contractors (Building Construction), Denver, Colorado

Henry T. Segerstrom,
Managing Partner, C. J. Segerstrom & Sons (Real Estate Development), Costa Mesa, California

E. L. Shannon, Jr.,
Chairman of the Board and Chief Executive Officer, Santa Fe International Corporation (Oil Service, Engineering,
Petroleum Exploration and Production), Alhambra, California

H. Russell Smith,
Chairman of the Executive Committee,
Avery International (Manufacturer of Self-Adhesive Products), Pasadena, California

(1) Mr. Carter, having reached retirement age, is not a nominee for reelection to the Board of Directors in 1984.

Executive Officers

William R. Gould,
Chairman of the Board and Chief Executive Officer

Howard P. Allen,
President

H. Frederick Christie,
Executive Vice President and Chief Financial Officer

David J. Fogarty,
Executive Vice President

(2)John E. Bryson,
Senior Vice President

P. L. Martin,
Senior Vice President

L. T. Papay,
Senior Vice President

A. Arenal,
Vice President

Kenneth P. Baskin,
Vice President (Nuclear Engineering, Safety and Licensing)

G. J. Bjorklund,
Vice President (Engineering and Construction)

Robert H. Bridenbecker,
Vice President (Fuel Supply)

John R. Bury,
Vice President and General Counsel

(3)Richard K. Bushey,
Vice President and Controller

Robert Dietch,
Vice President (Customer Service)

C. E. Hathaway,
Vice President (Human Resources)

Joe T. Head, Jr.,
Vice President (Power Supply)

(4)A. L. Maxwell,
Vice President and Comptroller

Charles B. McCarthy, Jr.,
Vice President (Advanced Engineering)

Edward A. Myers, Jr.,
Vice President (System Development)

M. L. Noel,
Vice President and Treasurer

(2)Michael R. Peevey,
Vice President (Revenue Requirements and Governmental Affairs)

Harold B. Ray,
Vice President and Site Manager, San Onofre Nuclear Generating Station

Robert E. Umbaugh,
Vice President (Administration)

Honor Muller,
Secretary

(2) Messrs. Bryson and Peevey were elected to their respective positions effective February 1, 1984.
(3) Mr. Bushey was elected Vice President and Controller effective January 1, 1984.
(4) Mr. Maxwell retired effective December 31, 1983.

Distribution of Record Shareholders and Shares as of December 31, 1983	Shareholders				Shares			
	Preferred	%	Common	%	Preferred	%	Common	%
Total Shareholders	33,415	100.0	158,186	100.0	20,144,746	100.0	100,468,012	100.0
Class of Investor								
Males	6,135	18.3	36,335	23.0	980,996	4.9	7,746,299	7.7
Females	13,290	39.8	56,514	35.7	1,916,150	9.5	10,687,799	10.6
Joint Accounts	8,861	26.5	44,572	28.2	1,652,403	8.2	9,202,950	9.2
Fiduciaries	2,935	8.8	17,030	10.8	558,886	2.8	3,687,622	3.7
Religious, Charitable, Fraternal and Educational Institutions	203	0.6	540	0.3	99,871	0.5	595,538	0.6
Financial Institutions	825	2.5	1,134	0.7	11,942,505	59.3	66,080,137	65.8
Other	1,166	3.5	2,061	1.3	2,993,935	14.8	2,467,667	2.4
Amount of Holdings								
1 to 99 shares	13,826	41.4	53,686	33.9	397,860	2.0	1,892,328	1.9
100 shares	7,465	22.3	32,737	20.7	746,500	3.7	3,273,700	3.3
101 to 499 shares	8,575	25.7	54,942	34.7	2,091,756	10.4	13,200,300	13.1
500 to 999 shares	1,929	5.8	11,325	7.2	1,155,234	5.7	6,822,280	6.8
1,000 or more shares	1,620	4.8	5,496	3.5	15,753,396	78.2	75,279,404	74.9
Geographical Location								
Service Territory	9,075	27.2	38,136	24.1	2,085,099	10.4	13,115,247	13.1
Remainder of California	11,036	33.0	46,699	29.5	3,178,264	15.8	25,361,680	25.2
United States (except California) and Possessions	13,242	39.6	72,817	46.0	14,873,686	73.8	61,820,962	61.5
Foreign Countries	62	0.2	534	0.4	7,697	—	170,123	0.2

1984 Annual Shareholders' Meeting:
The annual meeting of shareholders of Southern California Edison Company will be held at 10 a.m., Thursday, April 19, 1984, at the Company's Corporate Headquarters, 2244 Walnut Grove Avenue, Rosemead, California 91770. Telephone (818) 572-1212.

For Investor Relations:
Individual Shareholders contact:
Southern California Edison Company
Secretary's Department—Room 240
Post Office Box 400
Rosemead, California 91770
Telephone (818) 572-1997

Institutional Investors contact:
Supervisor, Investor Relations
Telephone (818) 572-2515
Assistant Treasurer
Telephone (818) 572-1090

Stock Transfer Agent:
Southern California Edison Company
Secretary's Department—Room 240
Post Office Box 400
Rosemead, California 91770
Telephone (818) 572-1393 or
(818) 572-1936

Dividend Reinvestment and Stock Purchase Plan Agent:
Southern California Edison Company
Secretary's Department—Room 240
Post Office Box 400
Rosemead, California 91770
Telephone (818) 572-1852 or
(818) 572-1995

Registrar of Stock:
Security Pacific National Bank
Los Angeles, California

Stock Exchange Listings:
Common Stock:
New York Stock Exchange
Pacific Stock Exchange
London Stock Exchange

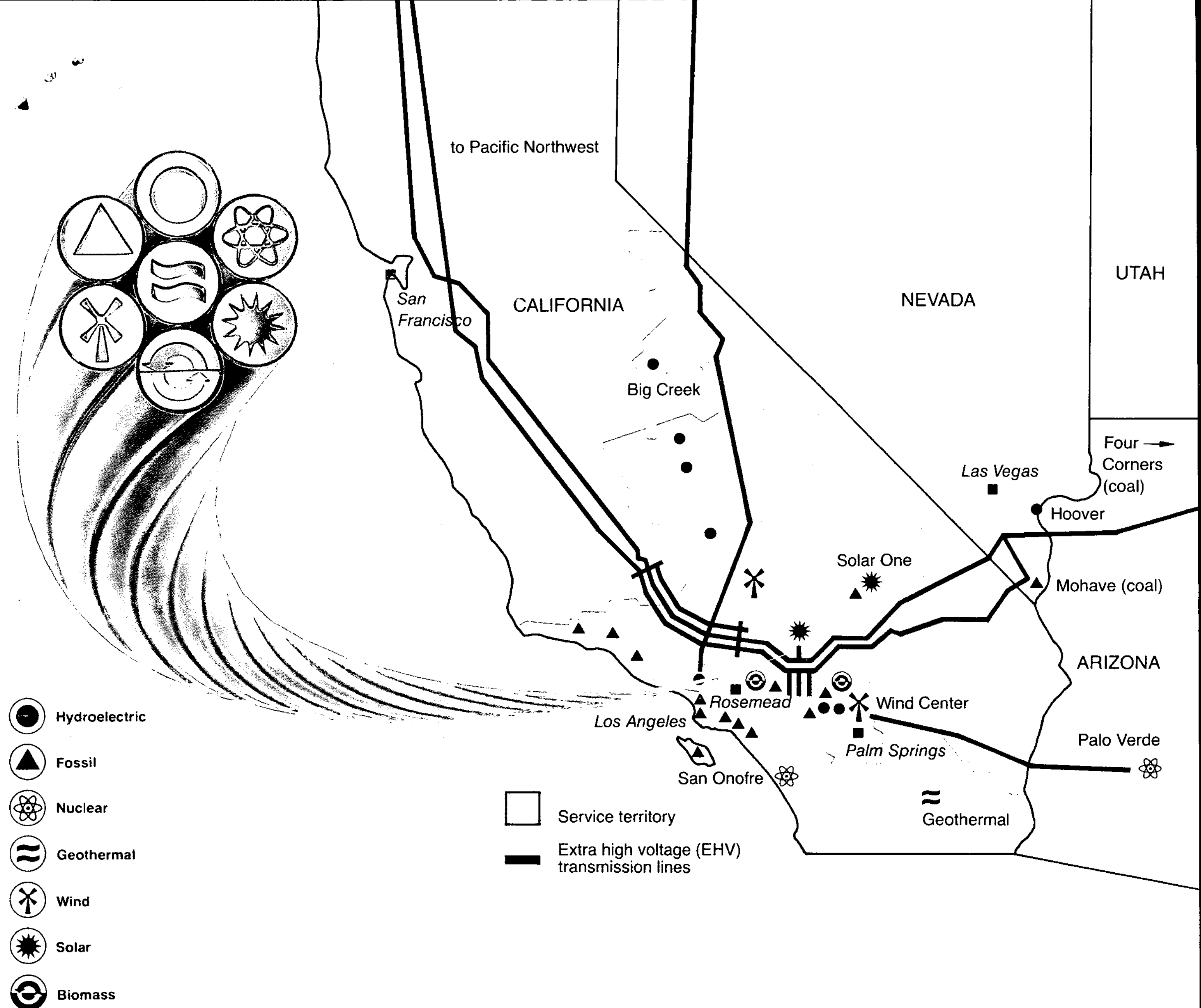
Preferred and Preference Stocks:
American Stock Exchange
Pacific Stock Exchange

Ticker Symbol:
SCE (Common Stock)

Media Listings:
SCalEd

Statistical Supplement:
A comprehensive financial and statistical supplement to this report is available in limited quantity. A copy may be requested by writing to the Supervisor of Investor Relations, Southern California Edison Company, P.O. Box 800, Rosemead, California 91770.

This Annual Report and the statements and statistics contained herein have been assembled for general informative purposes and are not intended to induce, or for use in connection with, any sale or purchase of securities. Under no circumstances is this report or any part of its contents to be considered a prospectus, or as an offer to sell, or the solicitation of an offer to buy, any securities.



Southern California Edison Company System...
more primary resources than any other electric utility in the world.

Southern California Edison Company provides electric service in a 50,000 square-mile area of Central and Southern California. This area includes some 800 cities and communities with a population of more than nine million people.

Edison's gross investment in utility plant totals nearly $11.9 billion. Area generating capacity at peak during 1983 totaled 16,365 megawatts (MW), which included 14,031 MW of Company-owned facilities and 2,334 MW of capacity from other sources. Of the Company-owned facilities, 73% was comprised of oil- and gas-fired generating units. SCE's interest in coal-fired generating units accounted for another 12%, and 7% was in hydroelectric generation. The Company's interest in a nuclear generating station accounted for the remaining 8%.

The Company, incorporated in 1909 under the laws of California, is a public utility and its retail operations are subject to regulation by the California Public Utilities Commission which has the authority, among other things, to establish retail rates and to regulate security issuances, accounting and depreciation. The Company's resale operations are subject to regulation by the Federal Energy Regulatory Commission as to rates on sales for resale, as well as to other matters, including accounting and depreciation.

The Company's planning and siting of new plant construction are subject to the jurisdiction of the California Energy Commission. Edison also is subject to various governmental licensing requirements, to Securities and Exchange Commission filing and disclosure requirements and to certain other federal, state and local laws and regulations, including those related to nuclear energy and nuclear plant construction, environmental protection, fuel supplies and land use.

Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, California 91770
(818) 572-1212