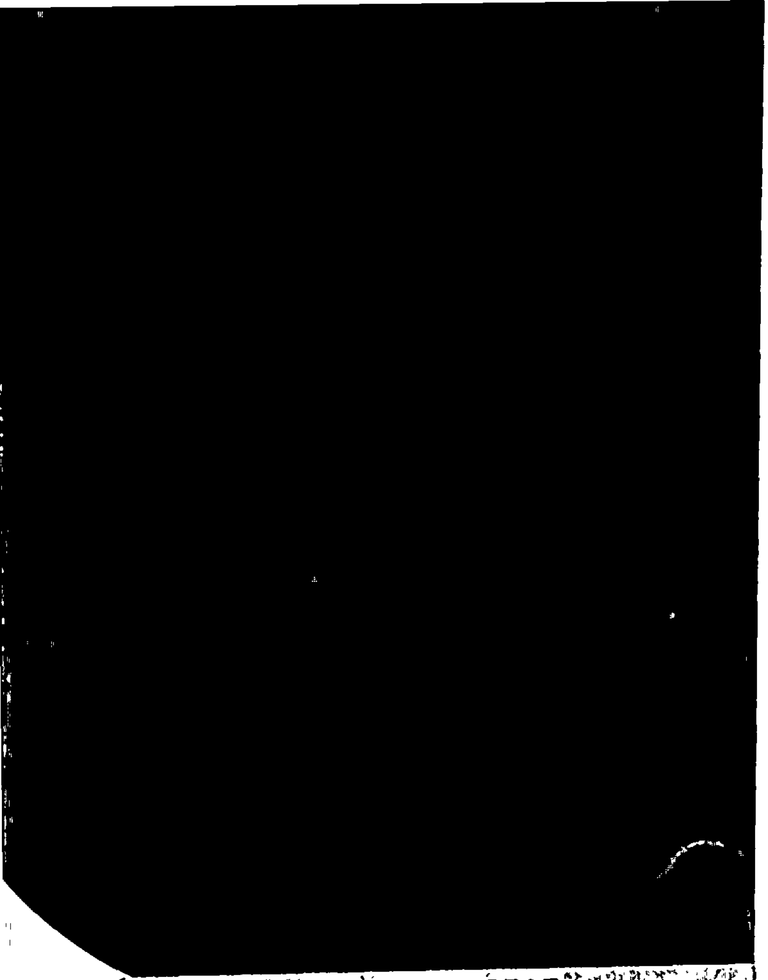
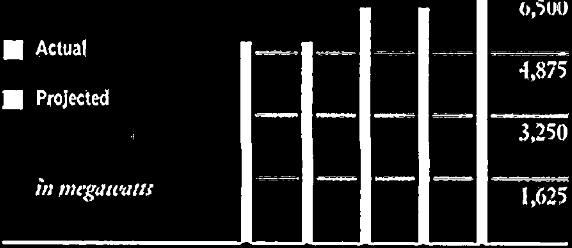
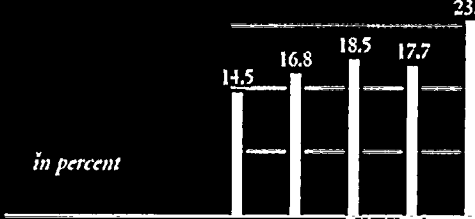


EDISON INTERNATIONAL 1997 ANNUAL REPORT


6,500
Actual
Projected
in megawatts
4,875
3,250
1,625


23
14.5
16.8
18.5
17.7
in percent

Key Financial Information

Dollars in millions, except per-share amounts	1997	1996	Increase (decrease)	5-year compound annual growth rate	10-year compound annual growth rate
PER SHARE:					
Basic earnings	$ 1.75	$ 1.64	6.7%	1.1%	0.3%
Diluted earnings	$ 1.73	$ 1.63	6.1	0.8	0.2
Dividends paid	$ 1.00	$ 1.00	—	(6.2)	(1.5)
Annual dividend rate at year-end	$ 1.00	$ 1.00	—	(6.5)	(1.7)
Stock price at year-end	$ 27 3/16	$ 19 7/8	36.8	4.3	6.0
Book value at year-end	$ 14.71	$ 15.07	(2.4)	2.0	2.9
FINANCIAL RATIOS:					
Dividend payout ratio	57.1%	61.0%	—	—	—
Rate of return on common equity	11.7%	11.1%	—	—	—
Market to book value	184.8%	131.9%	—	—	—
FOR THE YEAR:					
Revenue	$ 9,235	$ 8,545	8.1	3.0	5.1
Net income	$ 700	$ 717	(2.4)	(1.1)	(0.5)
AT YEAR-END:					
Assets	$25,101	$24,559	2.2	5.4	5.2
Capital structure					
Common equity	36.8%	43.9%	—	—	—
Preferred stock	4.1%	4.8%	—	—	—
Long-term debt	59.1%	51.3%	—	—	—

Edison International's Worldwide Operations

Edison International

Edison International is the parent company of Southern California Edison, Edison Mission Energy, Edison Capital, Edison Technology Solutions and Edison Enterprises, which includes Edison

In 1997, the achievements of Edison International were built on experience, growth and innovation: the experience of talented, dedicated employees; the growth in our company's assets to $25.1 billion and revenues to $9.2 billion; and innovation through the introduction of exciting new products and services. We are one company entering a new era with strong,

Achievement Experience Growth Innovation

related businesses, all poised to meet energy and infrastructure needs for the 21st century. We are focused on creating shareholder value by pursuing regional, national and international business opportunities. We are Edison International – The Power Behind Peace of Mind.

Dear Shareholders,

In 1997, the skill and hard work of Edison International people created excellent results. The goals most vital to our success for the year were meeting our earnings targets, achieving cost recovery objectives while helping create the new California electricity market, and building a strong platform

for future growth. I am happy to report that these goals were achieved. Returns to shareholders reflected this performance, substantially exceeding

The goals most vital to our success for the year were meeting our earnings targets, achieving cost recovery objectives while helping create the new California electricity market, and building a strong platform for future growth. I am happy to report that these goals were achieved.

most of our industry peers, and providing a total return of 42% in stock appreciation and dividends.

Earnings for Edison International increased to $1.75 per share from $1.64 in the prior year. Operating earnings increased by four cents per share. Although Southern California Edison's earnings declined, they exceeded our expectations. Strong sales and cost controls offset the effects of reduced returns associated with restructuring and two lengthy outages at the San Onofre Nuclear Generating Station.

Our principal nonutility companies set new earnings records. Edison Capital posted a 50% increase in earnings and a record 23% return on equity. Edison Mission Energy (EME) increased its earnings by 25%, and achieved a 12.2% return on equity. Together, Edison Capital and Edison Mission Energy contributed 25% of Edison International's total earnings, up from 18% in 1996.

Under the new California restructuring law, Southern California Edison is permitted within the next four years to recover approximately $5 billion in investments previously made as part of our utility service obligation. Most of these investments were in power generation, which becomes a strictly competitive enterprise in the new market. To recover those dollars, we must maintain strong service and reliable performance within tough cost disciplines. At the same time, we must increase revenues while operating under a rate freeze. In 1997, we did both, improving prospects for full recovery.

Three large transactions were particularly significant to cost recovery. First, from late last year to early this year, we reached agreements to sell 11 natural gas-fired power plants for a total price of $1.1 billion, or more than twice the book value of these plants. Second, during this same period, we entered into a $48 million hedge on natural gas costs to help offset the effect of potentially higher fuel prices on electricity costs over the next four years. Third, working with the State of California, we created and sold $2.5 billion in innovative notes, known as "rate reduction bonds." These bonds provided us cash for retirement of more expensive debt and equity at the utility, allowing for future investments and share repurchases at Edison International. They also made possible a 10% rate reduction for our residential and small business customers, which is now in effect.

Finally, in each of our businesses we built a strong foundation for future growth. Edison Capital made $520 million worth of investments, more than six times the previous annual average, including significant transactions in Australia and the Netherlands. Edison Mission Energy reached agreements for new power generation projects in Thailand and the Philippines with a combined capacity of 1,038 megawatts. EME also purchased the remaining 49% of our 1,000-megawatt, coal-fired power plant in Australia. Southern California Edison built pioneering systems for the new electricity market, while at the same time maintaining last year's top decile performance in distribution costs per customer. And we recruited accomplished leadership for our retail business, Edison Enterprises, which launched a series of new products and services in 1997.

Focus On Growth

For Edison International, growth is vitally important. Disciplined growth attracts and energizes talented people. That in turn builds increased shareholder value. We built value in 1997 by repurchasing 48 million shares of our stock at favorable prices and through recovery of prior utility investments. We will continue to give

In seeking growth, our highest priority will be investments in our existing businesses. We will also pursue extensions of those businesses into related areas where our experience and skills offer real potential for competitive advantage.

high priority to both share repurchases and cost recovery, but achieving increased value in the future will require, even more than in the past, new initiatives and investments. Over the last decade, we have grown Edison Mission Energy and Edison Capital into businesses whose combined assets exceed $6.7 billion. Now we need to continue and intensify that growth.

In seeking growth, our highest priority will be investments in our existing businesses. We will also pursue extensions of those businesses into related areas where our experience and skills offer real potential for competitive advantage. We will not take initiatives or invest in businesses unrelated to energy, infrastructure or those retail businesses which cannot build value from the Edison brand and reputation.

Within this country, restructuring and the movement to competition in power generation and retail markets provide new growth opportunities. Utility power plants valued at billions of dollars will be divested into competitive markets in the next several years. Edison Mission Energy should profit from this historic transformation. In new retail electricity markets, customized services, including particularly energy management outsourcing, will provide real customer benefits. Edison Enterprises should be a leader in this field.

Outside the United States, the trend toward privatization, the movement to competitive markets, and electricity's vital role in economic development all point to large growth opportunities. Traditionally, most electric systems around the world have been state-owned and managed. In the past five years, however, people and governments in country after country have seen the advantages of private businesses providing infrastructure and services. By taking risk and seeking reward, the private sector offers capital and skills which are rarely found in public undertakings. This means that governments, particularly in developing countries, can put scarce capital to other vital purposes while at the same time achieving more efficient development of electric systems.

<u>The risk inherent in new business initiatives can be mitigated, but it will not go away. We are nonetheless committed to growth, pursued with discipline and perseverance.</u>

Edison International has been an early mover in seeking out and capitalizing on these new opportunities. Our experience in Australia is a good example. In 1992, we pioneered the privatized market there with the purchase of 51% of the Loy Yang B power plant, then under construction by the State of Victoria. The initial experience with Loy Yang B, which we operate, was so positive for the State that it proceeded to sell off its entire electric system. This year we saw the opportunity to create another win-win outcome for the State of Victoria and our company. Edison Mission Energy's Bob Edgell led negotiations which resulted in our purchase of the remaining 49% of Loy Yang B. The State received a combination of cash and a substantial reduction in the price and duration of the government's power purchase obligation. Without acting early on privatization and without taking a new initiative last year, this excellent result would not have been possible.

As we seek to meet ambitious objectives, there will be many competitors, most of them well financed. The risk inherent in new business initiatives can be mitigated, but it will not go away. We are nonetheless committed to growth, pursued with discipline and perseverance. With the commitment and skills of our employees, we expect to capture a valuable share of the opportunities in these new and changing markets and thereby continue to reward your investment in us.

Board Changes

In 1997, we said farewell to our former chairman and CEO, Howard Allen, who announced his retirement from the board of directors in June, after 43 years of valuable and devoted service with the company. We also welcomed back Warren Christopher to the board of directors, following his distinguished tenure as Secretary of State of the United States. It is a privilege to work with your board of directors and the talented, dedicated employees of Edison International. We thank you for your support.

John E. Bryson

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

February 20, 1998

By any measure, the trauma team at Long Beach Memorial Medical Center in Southern California is one of the best in the business. At a moment's notice, surgeons, nurses and other specialists stand ready to provide emergency medical care. Twenty-four hours a day, seven days a week, this team of dedicated professionals comforts and cares for the people who pass through their doors. Of course, such commitment isn't new at Long Beach Memorial... it's part of the Medical Center's 90-year tradition of quality health care. And during those 90 years, Southern California Edison (SCE) has provided the Medical Center with a safe, reliable

Achievement

Experience

G r o w t h

Innovation

supply of electricity. In recent years, SCE has helped Long Beach Memorial save millions of dollars in energy costs, upgrade its lighting systems and protect its life-saving medical equipment against service interruptions. Just as the experienced professionals at Long Beach Memorial Medical Center are dedicated to saving lives, so too is Southern California Edison's team of experienced professionals dedicated to reliable electric service... any time, day or night.

from left: *Claudia Oneta, RN, Clinical Surgical ICU Nurse, Audrey Ellzey, RN, NP, PAC, Trauma Clinician and Brian Acker, MD, Director of Trauma Services.*

Experience is over a century of safe, reliable electric service

1997 was a strong year for Southern California Edison (SCE). SCE overcame substantial challenges to exceed its targeted earnings per share. The company also took significant measures, including plant divestiture, to prepare for California's new electricity marketplace, which was scheduled to open on March 31, 1998.

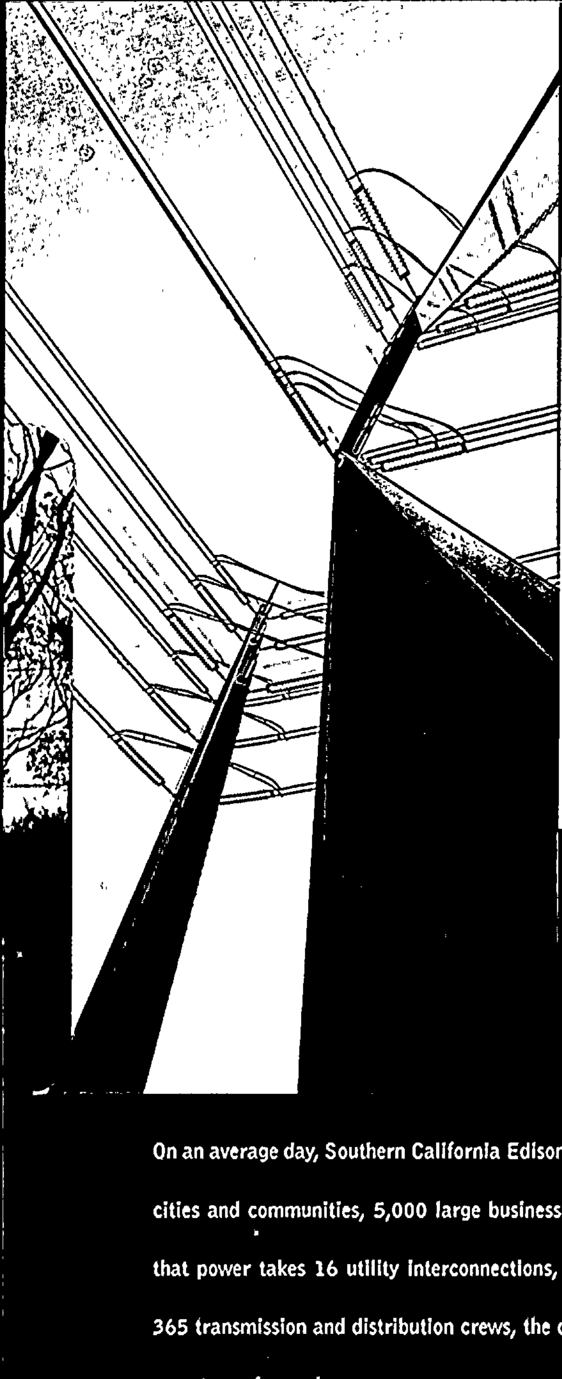
SCE's reported earnings per share were up two cents in 1997, to $1.44. SCE's per-share earnings increased despite the fact that total earnings fell 7.2%, to $576 million in 1997. Part of this reduction was anticipated because of lower authorized rates of return associated with accelerated recovery of SCE's investments at the San Onofre Nuclear Generating Station (SONGS) and the Palo Verde nuclear plant, and because of scheduled refueling outages at SONGS Units 2 and 3. Unscheduled outages for repairs at SONGS further reduced SCE's total earnings in 1997. However, the impact of this decline on earnings per share was offset by SONGS' strong performance following the outages, an increase in retail kilowatt-hour sales, the company's disciplined cost control and Edison International's aggressive stock repurchase program.

Preparing for a New Marketplace

In 1997, SCE prepared to facilitate California's new electricity marketplace by providing transmission, distribution and customer services at tariffed rates to its customers, who may choose to buy electricity either from SCE or from other, unregulated, power suppliers. SCE will have the opportunity to create value for Edison International shareholders in the new marketplace through recovery of its past investments and through cost-efficient operation. The company's achievements toward these ends were numerous:

- *Investment-cost recovery* — In December, SCE sold rate reduction bonds worth $2.5 billion. Issued in accordance with AB1890, California's electric utility industry restructuring law, the bonds financed a legislatively mandated 10% rate reduction for SCE's residential and small commercial customers, effective January 1, 1998. The first of their kind, the bonds have maturities ranging from one to 10 years, and will be repaid through a charge on customers' bills. The company applied the proceeds from the bond sale toward recovery of its past investments.

Between November 1997 and February 1998, SCE sold 11 of its 12 California gas-fired generating plants



On an average day, Southern California Edison turns on the power for 11 million people, 800 cities and communities, 5,000 large businesses and 280,000 small businesses. Delivering that power takes 16 utility interconnections, 4,900 transmission and distribution circuits, 365 transmission and distribution crews, the days and nights of 12,642 employees and over a century of experience.

for $1.1 billion, $614 million more than their book value. The divested plants included the Alamitos, Huntington Beach, Redondo, Long Beach, Coolwater, Mandalay, Ellwood, Etiwanda, El Segundo, San Bernardino and Highgrove generating stations. The company sold the plants, which have a combined generating capacity of 8,062 megawatts, to facilitate the transition to a competitive electricity-supply market in California. The divested plants were bought by established energy companies. The sales are anticipated to close concurrent with the start-up of California's competitive electricity generation and sales markets, scheduled for March 31, 1998. SCE will continue to operate and maintain the plants that remain in operation for at least two years following their sale, as required by AB1890.

The combined proceeds from the sale of rate reduction bonds and SCE's plant divestiture contributed more than $3.6 billion toward investment-cost recovery.

• *Controlling costs* — SCE continued to reduce operation and maintenance (O&M) expenses, exclusive of costs associated with refuelings at SONGS. SCE's non-nuclear O&M expenses, excluding recoverable costs incurred as a result of regulatory mandates, declined $35 million in 1997. Nuclear-related O&M costs, which included refuelings at SONGS Units 2 and 3, increased $46 million. Overall, the company's O&M expenses rose $11 million, or 0.8%. Capital costs rose from $674 million to $757 million, or 12%. About three-fourths of this increase resulted from expenses related to industry restructuring, information technology infrastructure and state-mandated marine environmental mitigation. SCE's combined capital and O&M expenses in 1997 remained $400 million lower than in 1994, and the company continued to operate at a high level of cost efficiency as it prepared to enter the new marketplace.

• *Sales growth* — In 1997, SCE also demonstrated its ability to retain and grow retail kilowatt-hour (kWh) sales, which will be critical to both the collection of the company's past investment costs and to future growth in earnings. For the 12 months ending December 31, retail sales rose 2.3 billion kWh, from 73.8 billion to 76.1 billion. This increased sales volume generated $89 million in additional revenue for the company. Economic growth in Southern California contributed substantially to the company's gain in kWh sales. SCE further enhanced this growth through a number of means, including cogeneration bypass prevention, programs to encourage customers to use electricity instead of gas, business and economic development and targeted load growth programs.

• *Facilitating the new marketplace* — In 1997, SCE prepared to coordinate its operations with the Independent System Operator (ISO), which controls the dispatch of electricity into the state's transmission grid, and the Power Exchange (PX), which provides transparent commodity pricing for electricity. Among its achievements, SCE developed a computer interface between the ISO and the company's energy control centers, modified its automatic generation control equipment to receive instructions from the ISO, and installed ISO-certified metering at its generating stations and its transmission system intertie points.

The company also established new procedures to bid SCE's power generation into the PX, to forecast load demand, and to purchase energy on behalf of customers who elect to continue receiving all their electricity services from the utility. SCE additionally established new procedures to handle requests from customers who elect to buy commodity electricity, and related services such as metering and billing, from providers other than the utility.

EXCELLENT OPERATIONAL PERFORMANCE

As SCE prepared for the new marketplace, the company recorded important achievements in its ongoing utility operations.

• *Service reliability* — SCE continued to improve the reliability of its transmission and distribution service. In 1997, reliability, as measured by average customer minutes interrupted, improved 12% over 1996. SCE has historically scored in the U.S. electric utility industry's top quartile on service reliability.

The company's power production business unit also posted an outstanding performance in 1997, successfully meeting a series of all-time peak demands during heat waves in August and September.

• *Employee safety* — SCE improved the safety of its operations in 1997, reducing the company's Occupational Health and Safety Administration recordable accident rate by 15%.

• *Increased revenues through performance excellence* — 1997 was the first year SCE operated under performance-based ratemaking (PBR), which enables the company to share savings from cost-efficient operations with its

In the restructured electric utility marketplace, Southern California Edison will provide utility services on regulated and nondiscriminatory terms for every customer within its service territory. In 1997, SCE's Customer Solutions Business Unit introduced the Energy Advisor concept. This program originated as a way to educate and prepare customers for success in the new marketplace. It now assists them in adapting to the changing regulatory environment, and enables them to make the best choice among providers of electricity, whether SCE or another electric service provider.

customers. Under PBR, the company also has the opportunity to achieve revenue awards of up to $51 million annually by surpassing performance targets for service reliability, employee safety and customer satisfaction. Conversely, SCE can be penalized up to $51 million annually for failing to meet these targets.

In 1997, SCE met its PBR target for customer satisfaction and exceeded its targets for service reliability and employee safety. Revenue awards and penalties for service reliability are calculated over a two-year period. The company's performance under PBR's bonus/penalty provisions for employee safety in 1997 entitled SCE to file for $5 million in performance awards in 1998.

- *Economic development* — The economic health of Southern and Central California is very important to SCE's revenues and earnings. The company has worked since 1992 to strengthen the region's economy by supporting small- and medium-size businesses. In 1997, SCE helped 100 companies either remain in the region, expand their businesses or relocate to Southern and Central California, saving or creating more than 15,000 jobs. Over the past five years, SCE has assisted more than 525 companies. SCE's efforts have helped save or create more than 118,000 jobs and preserve nearly 3.6 billion kilowatt-hours in electricity sales.
- *SONGS* — SONGS Unit 2 began the year in a refueling and maintenance outage that ended on April 1. Unit 3's refueling and maintenance outage began on April 12 and ended on July 21. During the outages, SONGS employees completed a first-time steam generator chemical cleaning project on both units. Extensive steam generator inspections and additional repairs were also completed during the outages.

  Following their respective outages, both units at SONGS ran continuously for the remainder of 1997, achieving a site capacity factor of 71% while generating a total of 10 million megawatt-hours for Edison customers.
- *Mohave Generating Station* — SCE's Mohave Generating Station achieved a capacity factor of better than 70% for the seventh consecutive year.
- *Edison Pipeline and Terminal Company* — Established in 1994 to create value for shareholders by making SCE's extensive oil pipeline and storage facilities available to other companies, Edison Pipeline and Terminal Company (EPTC) recorded a dramatic increase in revenues and net earnings. In 1997, EPTC's revenues were $20.4 million, a 39.7% increase over 1996. EPTC's net earnings rose 15% to $4.5 million.
- *Electric transportation* — SCE continued to provide important support for the commercialization of non-polluting electric vehicles (EVs). The company entered an alliance with Toyota Motor Sales to lease 80 electric vehicles for its fleet and to extend its lease-only arrangements for Toyota's RAV4 EV to employees of the utility and Edison International who live in SCE's service territory. A pioneer in the EV arena, the company continues to operate one of the most extensive utility EV fleets in the U.S. Its EV Technical Center in Pomona, California is one of two national "qualified testers" for the U.S. Department of Energy.

The Power Behind Peace of Mind is…

At the Healesville Sanctuary, about 65 miles east of Melbourne, Australia, more than 200 animal species – including the kangaroo, koala and platypus – flourish in a unique bush-land environment. Thanks to its breeding program for endangered species and its efforts to restore wildlife habitat, the Healesville Sanctuary is one of the State of Victoria's most prized treasures. And it's in this region rich in natural history and wildlife that Edison International is investing in the infrastructure that supplies much needed electricity to both residential customers and commercial ventures like the Healesville Sanctuary.

Achievement

Experience

Growth

Innovation

In May, Edison Mission Energy became the sole owner of the Loy Yang B power plant near Melbourne, acquiring the 49% ownership share of the plant previously held by the State of Victoria. Likewise, Edison Capital strengthened its Australian presence by investing $161 million in a cross-border lease of South Australia's electric power transmission system. In the years ahead, Edison International will continue to grow its business and build shareholder value... not just in Australia, but in countries around the world.

AT LEFT: *Kate Miller, Animal Keeper at Healesville Sanctuary.*

Edison Mission Energy (EME) sustains its leading performance in global power production by following a rigorously exacting approach to investment opportunities. The company carefully evaluates the risks and potential returns of proposed projects to create long-term value for Edison International shareholders. In 1997, Edison Mission Energy continued the disciplined approach toward new investment that is its hallmark.

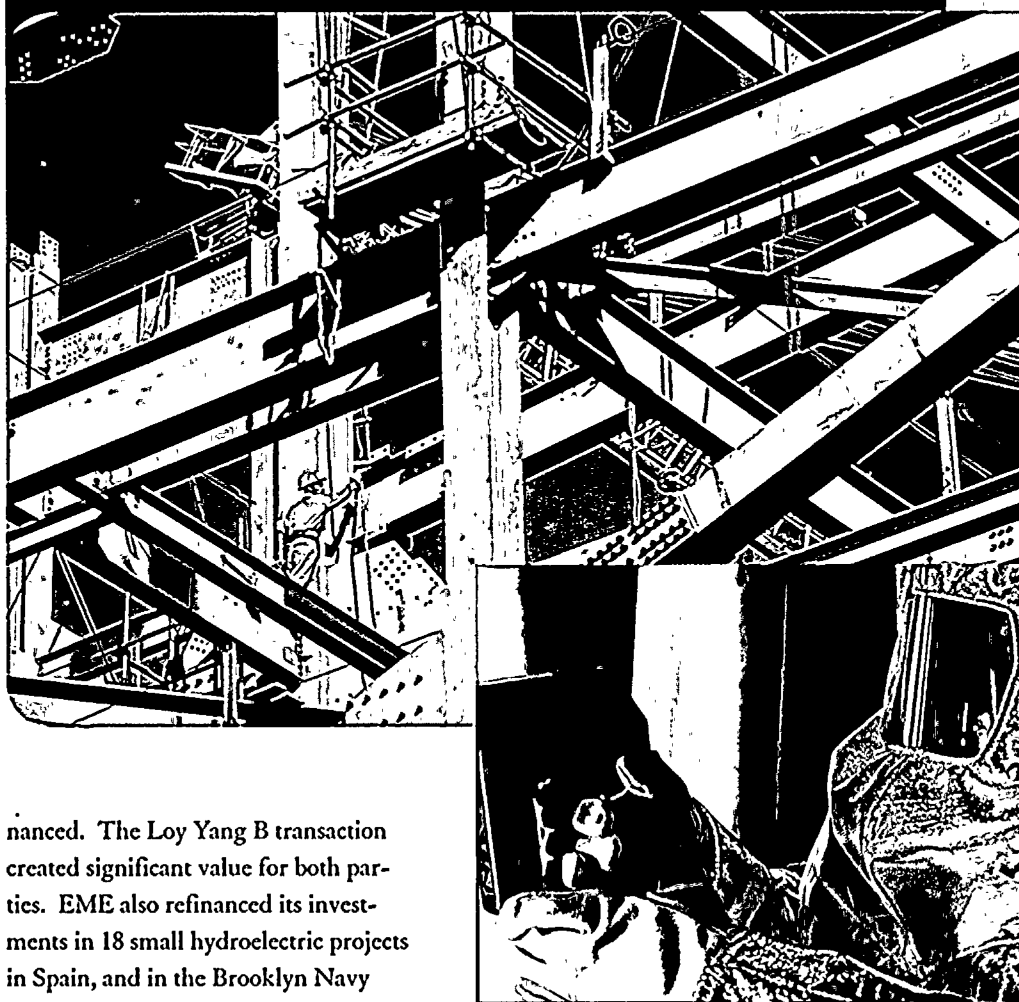
Strong Performance

1997 was a strong year for Edison Mission Energy. Earnings grew 25% to $115 million, while revenues rose 15.6% to $975 million. EME has $5 billion in assets and interests in 55 projects totaling more than 10,000 megawatts, including 50 projects in operation, three under construction and two in advanced development.

Strategic Transactions

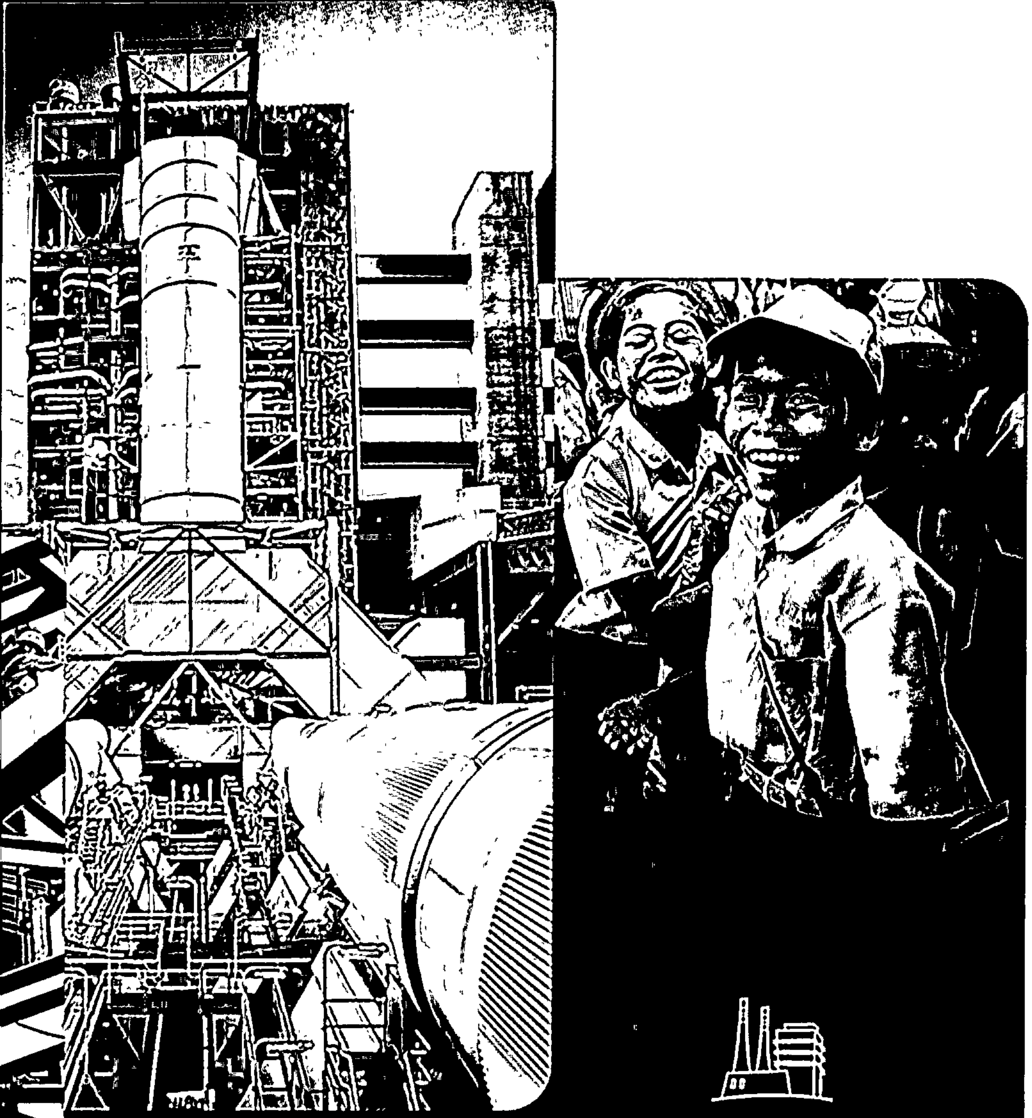
In May, Edison Mission Energy became the sole owner of the Loy Yang B power plant near Melbourne, Australia, acquiring the 49% ownership share of the plant that was previously held by the State of Victoria. This acquisition was achieved through a complex transaction in which the project agreements governing electricity sales, fuel supply and infrastructure services were renegotiated and the entire project was refinanced. The Loy Yang B transaction created significant value for both parties. EME also refinanced its investments in 18 small hydroelectric projects in Spain, and in the Brooklyn Navy Yard cogeneration plant, enhancing the value of all these assets.

Growth is leading the way in global energy markets



Progress on Major Projects

- *Indonesia* — The $2.5 billion, 1,230-megawatt Paiton project proceeded on schedule, and is now 85% complete. Edison Mission Energy owns 40% of the project, which is expected to begin commercial operation in 1999.
- *Italy* — Construction on the 512-megawatt ISAB gasification project in Sicily is now 75% complete. The ISAB plant will convert high-sulfur oil refinery waste to low-sulfur



Edison Mission Energy specializes in the development, acquisition, construction management and operation of global power production facilities. As one of the world's leading developers, Edison Mission Energy's investments include 55 projects totaling more than 10,000 megawatts of generation capacity that are in operation, under construction or in development. Edison Mission Energy has built an excellent reputation and strong partnerships — with governments, utilities, lenders and investors — based on its ability to develop cost-effective, environmentally sound projects that provide long-term benefits to the customers it serves, its partners and the company.

"syngas" for power generation, while recycling the recovered sulfur for sale to the agriculture and chemical industries. EME owns 49% of the ISAB project. The remaining 51% is owned by ERG Petroli S.p.A., owner of the ISAB refinery and an affiliate of the ERG Group. In 1997, the ISAB project received the Innovative Project Award from Independent Energy magazine, which covers the global independent power production industry.

- *Turkey* — In April, construction began on the 180-megawatt Doga Enerji cogeneration project near Istanbul. The project will be one of the cleanest burning fossil fuel facilities in Turkey and will provide heat for 14,000 new homes, eliminating the need for those homes to burn polluting fuels for heating.
- *Philippines* — Edison Mission Energy continued development of the San Pascual project, a 304-megawatt cogeneration plant scheduled for start-up in early 2001. The plant will supply steam to a nearby refinery and an industrial complex, and will sell electricity to National Power Corporation, the state-owned electric utility company, under a power-purchase agreement signed in September. It will be the largest cogeneration project in the Philippines.
- *Thailand* — Development proceeded on the two-unit, 734-megawatt Kui Buri project. EME will hold a 40% interest in the facility, which will be fueled by low-sulfur coal. A power-purchase agreement for the plant was concluded in December. The plant's first unit is scheduled for completion in the fourth quarter of 2001, and the second unit is scheduled for completion in the second quarter of 2002.

EDISON CAPITAL

Edison Capital, Edison International's capital and financial services subsidiary, marked its 10th year in operation. It was an outstanding year for the company.

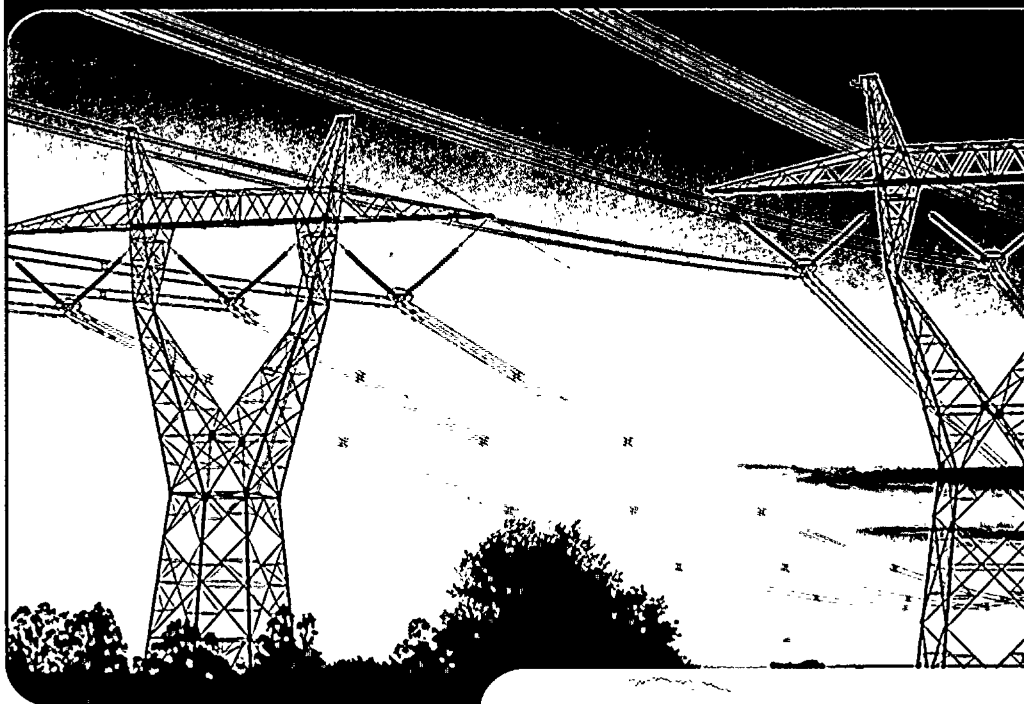
FINANCIAL RESULTS

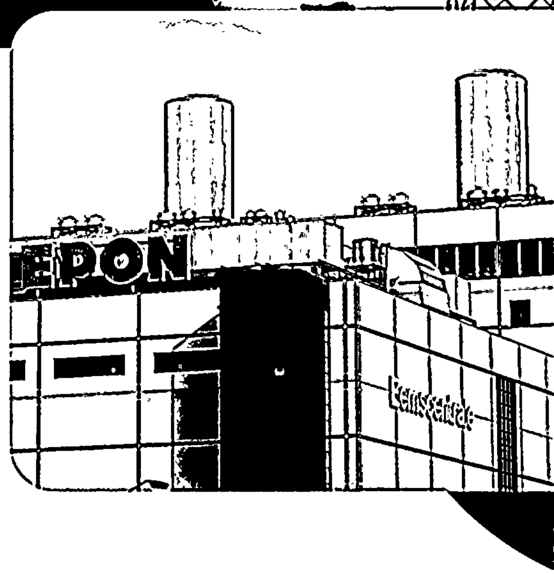
Edison Capital earned a record $60.8 million in 1997, up 50% over the previous year. The company's net income has grown at an average rate of 24% annually since Edison Capital's inception in September 1987. Edison Capital's return on common equity, which averaged 18.5% over the last 10 years, was 23.2% in 1997. The increases are due to investments in power generation, transmission and affordable housing projects. During 1997, Edison Capital invested $520 million, more than six times its historical annual average level of $85 million. Edison Capital has assets of $1.8 billion and an A- rating from Standard and Poor's.

ENERGY/ INFRASTRUCTURE TRANSACTIONS

Edison Capital strengthened its presence in global energy and infrastructure markets by investing $356 million

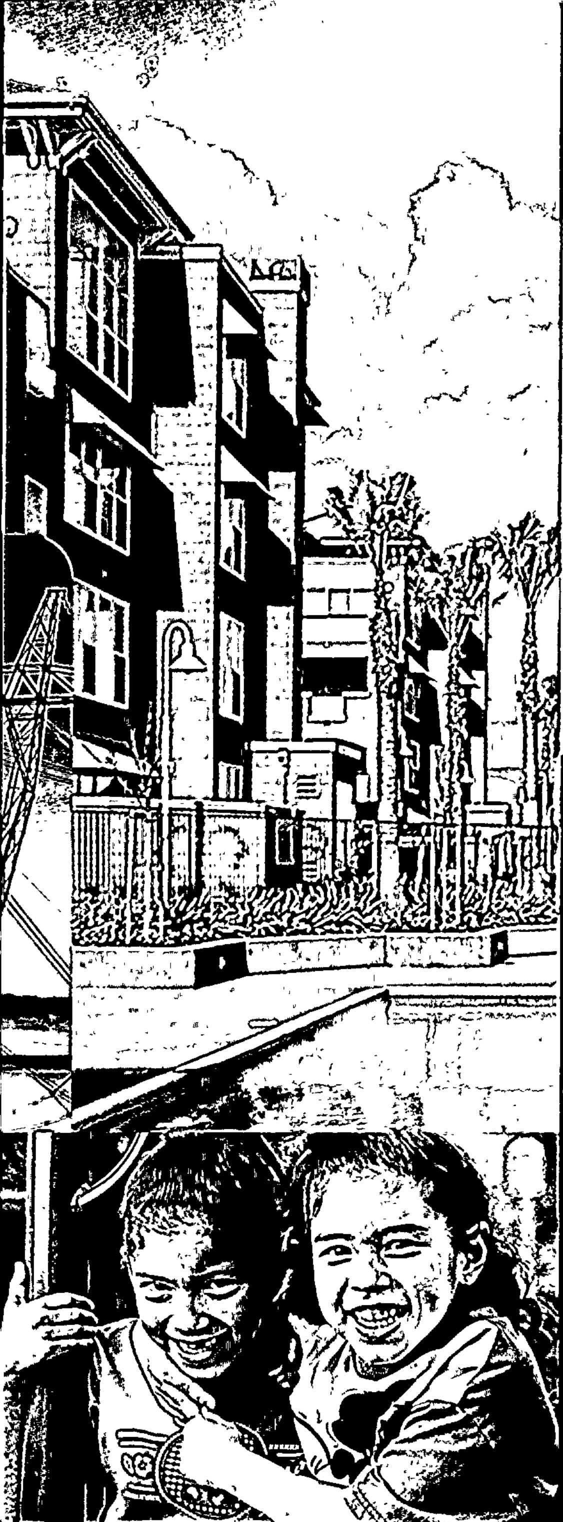
Growth is a diversified portfolio of investments





in the Netherlands, South Australia and Latin America. The company acquired an interest in the new Eems Power Station near Gronhingen, Netherlands. The plant is operated by EPON, the Netherlands' largest power generation company. The investment in this cross-border lease transaction is approximately $188 million. Edison Capital also acquired an interest in the electric power transmission system of South Australia, investing $161 million in a cross-border lease of the system.

Edison Capital's participation in the $1 billion AIG/GE Capital Latin American Infrastructure Fund has



been very active since its formation in 1996. The fund has committed to investments in energy, telecommunications and transportation projects in Bolivia, Brazil, Mexico, Trinidad and Argentina. Edison Capital also co-invested with the Latin Fund in a methanol production facility in Trinidad. The company also entered into investment commitments for infrastructure projects in Scotland and Bolivia.

Edison Capital is a provider of capital and financial services in two key areas: energy/infrastructure and affordable housing. The company's investments in global infrastructure include transmission and distribution systems, cogeneration, hydroelectric, nuclear, waste-to-energy and electric rail projects.

With the acquisition of the San Francisco-based John Stewart Company, a diversified housing management company, Edison Capital has enhanced its leadership position in the affordable housing marketplace.

Affordable Housing

Edison Capital continued to expand its affordable housing portfolio in 1997 with the investment of a record $164 million in 63 projects. The company placed 41 projects in service, also a record high, and 70% more than in 1996, and has committed $217 million to 83 new projects to be placed in service in 1998 and 1999. The strength of Edison Capital's affordable housing portfolio was proven with the closing of five syndications of housing commitments to four major institutional investors. At year's end, Edison Capital's portfolio included 279 projects, totaling 20,714 units of housing.

Edison Capital also acquired the John Stewart Company, a leading diversified management company specializing in affordable housing. By acquiring the John Stewart Company, Edison Capital will be able to expand the services it offers and draw upon the John Stewart Company's expertise to enhance Edison Capital's leadership position in the affordable housing market.

The Power Behind Peace of Mind is...

For the Perez family of Southern California, the power of Edison Security Services is the power to protect. Carlos Perez and his wife, Rose, wanted to safeguard their house and property, and they wanted to protect what makes that house a home...their two young daughters, Lauren and Gabriella. After researching several security systems, the Perez family selected Edison Security Services for its full-featured, dependable system, and because it's backed by the power of the Edison name. In addition to Edison Security Services, the Perez

Achievement

Experience

Growth

Innovation

family and other retail and small business customers can choose from a number of products and services from Edison Select, including Edison OnCall℠ Electrical, Appliance and Computer Repair, Disaster Preparedness Kits, and Edison OnCall℠ Internet Access Service, which features a high-speed, reliable connection to the World Wide Web. For safety, comfort and convenience, Edison Select is truly the Power Behind Peace of Mind.

at left: *The Perez Family — Rose, Carlos, Lauren and Gabriella.*

In 1997, Edison International's previously established retail products and services businesses — Edison Source, Edison EV and Edison Select — were consolidated under Edison Enterprises. Consolidation of existing and new retail businesses under Edison Enterprises will enable them to take advantage of shared staff resources and realize economies of scale as they expand into new markets.

Edison Enterprises positioned its businesses for future growth in shareholder value through a number of significant steps in 1997.

Growth of existing businesses

• *Energy services outsourcing* — Edison Source formalized its customer relationship with Vons supermarkets, a division of Safeway, by reaching agreement to provide integrated energy outsourcing services to 163 stores. The comprehensive energy management contract will benefit the supermarket chain through improved operation and management of their Southern California store facilities. Under the agreement, technical services provided by Edison Source include operation and maintenance for refrigeration, heating, ventilation, air conditioning, lighting and other electrical systems equipment.

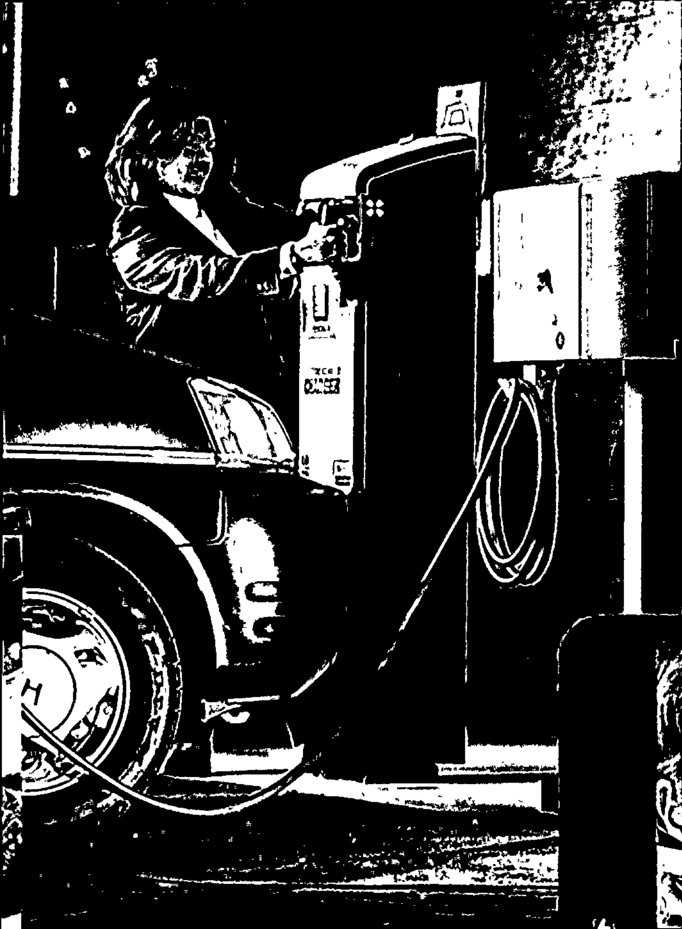
• *Electric vehicle charging* — Edison EV supplemented its existing alliances with General Motors Corporation and Saturn Corporation by forging ties to American Honda Motor Company, Toyota Motor Sales, Ford Motor Company, and to additional electric vehicle charging manufacturers, to serve electric vehicle customers nationwide.

Innovation is creating exciting new retail products and services

New products launched

• *Renewable energy* — Edison Source introduced EarthSource℠, one of the first renewable energy products available to residential and small business customers in California's new electricity marketplace. EarthSource℠ power will come from clean, natural sources, such as solar, wind, biomass, geothermal and small hydro generators. Edison Source is offering customers two options: *EarthSource 50,* which allocates half of a customer's energy dollars to the purchase of renewable power; and *EarthSource 100,* allocating all of a customer's energy dollars to power from renewable sources. Under the first option, customers' energy bills will remain about the same as in the past. Under the second option, customers will pay about 15% more for their electricity.

• *Home services* — Edison Select launched Edison OnCall℠ Electrical,



Appliance and Computer Repair services. It also introduced Edison Security Services and offered Disaster Preparedness Kits. By the end of the year, Edison Select had signed up more than 60,000 customers for these new retail products and services.

New business initiatives

- *Edison Utility Services* — Established in December 1997, Edison Utility Services will offer a diverse range of services to electric utilities in the U.S. and Canada, including — but not limited to — billing, outage management and transmission and distribution outsourcing.
- *Edison Utility Alliances* — This special corporate unit was formed in December 1997 to market Edison Enterprises' retail consumer products nationwide through alliances with electric and gas utilities.

Edison Enterprises, the retail arm of Edison International, includes Edison Source, which specializes in bringing energy management solutions to residential and business customers; Edison EV, the leading provider of electric vehicle charging systems and infrastructure; Edison Select, which markets a broad range of consumer products and services; and Edison Utility Services, which specializes in billing, outage management and transmission and distribution outsourcing services. Each of these companies is focused on providing innovative products and services that meet the needs of a wide range of customers while building on the Edison brand.

Financial Information

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

Results of Operations

Earnings

Edison International's 1997 basic earnings per share were $1.75, compared with $1.64 in 1996 and $1.66 in 1995. Southern California Edison (SCE) earned $1.44 in 1997, compared with $1.42 in 1996 and $1.44 in 1995. Edison Mission Energy (EME), Edison Capital and Mission Land Company had combined earnings of 44¢, up from 27¢ in 1996 and 23¢ in 1995. Edison International's earnings include special charges of 7¢ in 1996 (a 4¢ net charge at SCE for workforce management costs and reserves, and a 3¢ charge at Mission Land for real estate reserves) and 3¢ in 1995 for SCE's workforce management expenses. Edison Enterprises (Edison International's retail arm comprised of Edison Source, Edison EV, Edison Select and Edison Utility Services) and the Edison International parent company had combined expenses of 13¢ in 1997, compared with 5¢ in 1996 and 1¢ in 1995.

Edison International initiated a share repurchase program in 1995 to increase shareholder value. Its Board of Directors has authorized repurchases of up to $2.3 billion in outstanding shares. In 1997, over 48 million shares were repurchased for $1.2 billion. From the inception of the program through year-end 1997, Edison International has repurchased over 72 million shares for $1.6 billion.

1997 vs. 1996

SCE's 1997 earnings of $1.44 per share were 2¢ lower than 1996 (excluding 1996 special charges noted above). The decrease is mainly due to lower earnings from an extended refueling outage at the San Onofre Nuclear Generating Station. The decline was almost completely offset by higher sales, lower non-nuclear operating expenses and the effect of Edison International's share repurchase program. EME and Edison Capital had combined earnings of 44¢ in 1997, up 14¢ over 1996. EME contributed a record $115 million to earnings in 1997, compared with $92 million in 1996, an increase of 25%. The increase is primarily due to higher earnings from EME's foreign projects, partially due to lower tax rates. Edison Capital contributed a record $61 million to earnings in 1997, up 50% over the prior-year earnings of $41 million. Edison Capital's earnings benefited substantially from two cross-border lease investments and a record high level of affordable housing investments. Edison Capital and EME together contributed 25% of Edison International's total earnings, up from 18% in 1996. Continued start-up costs at Edison Enterprises, combined with interest expense at the Edison International parent company, were 8¢ per share more in 1997 than 1996.

The reduced number of outstanding shares benefited Edison International's earnings per share by 15¢ in 1997, when compared with 1996.

1996 vs. 1995

Excluding special charges, SCE's 1996 earnings per share were $1.46, down 1¢ from 1995. The decrease is mainly attributable to a reduction in authorized rates of return and authorized operating expenses, partially offset by improved operating performance.

The combined 1996 earnings of EME, Edison Capital and Mission Land, excluding nonrecurring items, were 30¢, 7¢ higher than in 1995. The increase is primarily due to higher earnings from EME's First Hydro project in the United Kingdom, which was acquired in December 1995.

Continued start-up costs at Edison Enterprises, combined with interest expense at the Edison International parent company, were 4¢ per share more in 1996 than 1995.

The reduced number of outstanding shares benefited Edison International's earnings per share by 3¢ in 1996 versus 1995.

Operating Revenue

Electric utility revenue increased 5% over 1996, due to an increase in sales volume and customer refunds in 1996. There were no comparable refunds in 1997. The increase in volume is mainly attributable to the overall increase in retail sales among residential and commercial customers. Operating revenue in 1996 decreased 4% from 1995, as increased sales volume was offset by lower average rates. The lower rates were attributable to the California Public Utilities Commission's (CPUC) decision to lower SCE's 1996 authorized revenue by 4.4%. Additionally, during 1996, SCE's customers received a one-time bill credit totaling $237 million as part of a CPUC-ordered refund of energy cost balancing account overcollections. In 1997, over 98% of SCE's operating revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

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

The changes in electric utility revenue resulted from:

In millions *Year ended December 31,*	*1997*	*1996*	*1995*
Electric utility revenue —			
Rate changes (including refunds)	$ 173	$ (522)	$ 168
Sales volume changes	193	206	(129)
Other	4	26	35
Total	$ 370	$ (290)	$ 74

Legislation enacted in September 1996 provided for, among other things, at least a 10% rate reduction (financed through the issuance of rate reduction notes) for residential and small commercial customers in 1998 and other rates to remain frozen at the June

10, 1996, level (system average of 10.1¢ per kilowatt-hour). See discussion in Competitive Environment.

Revenue from diversified operations increased 33% in 1997 primarily due to the start-up of EME's Loy Yang B Unit 2 and Kwinana projects. These facilities began commercial operations during the fourth quarter of 1996. In addition, revenue from diversified operations increased, due to higher energy sales from EME's First Hydro project combined with substantial increases at Edison Capital from its cross-border lease investments and Mission Land from the sale of $63 million in real estate during the second quarter. Revenue from diversified operations increased substantially during 1996, due to an increase in EME's electric revenue from its First Hydro, Iberian Hy-Power and Loy Yang B Unit 2 projects.

Operating Expenses

Fuel expense increased 40% in 1997. The increase is due to a $174 million gas contract termination payment during the third quarter, combined with higher gas prices and the extended refueling outages at San Onofre. San Onofre Unit 2 was shut down during the entire first quarter of 1997, Unit 3 was shut down 80 days of the second quarter and both units had a combined outage time of 30 days during the third quarter, which resulted in an overall increase in gas-powered generation for the year. There were no comparable outages in 1996. EME's fuel expense also increased in 1997 due to the start-up of the Kwinana project in the fourth quarter of 1996 and higher pumping costs at the First Hydro project (a pumped-storage facility which pumps water at night for storage in reservoirs and then allows it to flow back to generate electricity when it is needed during the day) due to increased generation and higher prices. Fuel expense increased 11% in 1996, compared to 1995, due to higher gas prices and changes in the fuel mix. EME's 1996 fuel expense increased due to Loy Yang B Unit 2, Kwinana and the inclusion of pumping costs related to First Hydro.

Purchased-power expense increased slightly in 1997 and 1996, due to increases in spot market purchases and increases in power purchased under federally mandated contracts. SCE is required under federal law to purchase power from certain nonutility generators even though energy prices under these contracts are generally higher than other sources. In 1997, SCE paid about $1.6 billion (including energy and capacity payments) more for these power purchases than the cost of power available from other sources. The CPUC has mandated the prices for these contracts.

Provisions for regulatory adjustment clauses decreased substantially in 1997, due to undercollections in the energy cost balancing account as actual energy costs (including the gas termination payments discussed above) exceeded CPUC-authorized fuel and purchased-power cost estimates. In addition, there were undercollections associated with SCE's direct access activities (see discussion in Competitive Environment—Direct Customer Access), research and development activities and San Onofre. These undercollections were offset by overcollections related to actual base-rate revenue from kilowatt-hour sales exceeding CPUC-authorized estimates and the final settlement of SCE's Canadian supply and transportation contracts (see discussion in Regulatory Matters). The provisions for regulatory adjustment clauses also decreased in 1996 from 1995 due to lower than authorized base-rate revenue, undercollections related to the accelerated recovery of SCE's remaining investment in San Onofre Units 2 and 3 and the $237 million refund to ratepayers during 1996 for prior energy cost balancing account overcollections.

Other operating expenses increased 15% in 1997, primarily due to start-up expenses at Edison Enterprises and increased administrative costs at EME, Edison Capital and Mission Land. Other operating expenses increased 10% in 1996 when compared with 1995, as increased operating costs at EME's First Hydro, Iberian Hy-Power and Loy Yang B Unit 2 projects and higher administrative costs offset cost reductions and strong operating performance at SCE.

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

Depreciation and decommissioning expense increased 16% in 1997. The increase is due to increases in plant assets and the accelerated recovery of the Palo Verde Nuclear Generating Station units effective January 1997. Depreciation and decommissioning expense increased 16% in 1996, compared to 1995, due to higher depreciation rates, the accelerated recovery of San Onofre Units 2 and 3 starting in April 1996, and increases at EME related to its Loy Yang B Unit 2 and Kwinana projects.

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

Other Income and Deductions

The provision for rate phase-in plan reflects a CPUC-authorized, 10-year rate phase-in plan, which deferred the collection of revenue during the first four years of operation for the Palo Verde units. The deferred revenue (including interest) was collected evenly over the final six years of each unit's plan. The plan ended in February 1996, September 1996 and January 1998 for Units 1, 2 and 3, respectively. The provision is a non-cash offset to the collection of deferred revenue.

Interest and dividend income increased 35% in 1997, due to increases in interest earned on SCE's balancing accounts and increases in dividend income from SCE's equity investments.

Minority interest decreased in 1997, due to EME's May 1997 acquisition of the remaining 49% ownership interest in the Loy Yang B project. Minority interest increased 46% during 1996, primarily from higher pre-tax income at EME's Loy Yang B Unit 2.

Other nonoperating income decreased substantially in 1997, due to additional accruals for regulatory matters associated with the restructuring of California's electric utility industry. Other nonoperating income also decreased in 1996, compared to 1995, due to regulatory accruals in 1996.

Interest and Other Expenses

Interest on long-term debt decreased in 1997, due to the early retirement of $400 million of first and refunding mortgage bonds in July 1997, partially offset by additional interest expense associated with the issuance of approximately $2.5 billion in rate reduction notes in December 1997 (see discussion in Cash Flows from

Financing Activities). Interest on long-term debt increased 12% in 1996 compared with 1995, reflecting EME's increased ownership in Iberian Hy-Power and First Hydro.

Other interest expense increased substantially in 1997, due to higher levels of short-term debt used to retire first and refunding mortgage bonds, discussed above. Other interest expense increased 11% during 1996, due to a $350 million borrowing by Edison International (holding company) for the acquisition of First Hydro and for its ongoing share repurchase program.

Financial Condition

Edison International's liquidity is primarily affected by debt maturities, dividend payments, capital expenditures, and investments in partnerships and unconsolidated subsidiaries. Capital resources include cash from operations and external financings.

Edison International's Board of Directors has authorized the repurchase of up to $2.3 billion of its outstanding shares of common stock. Edison International has repurchased 76.9 million shares ($1.7 billion) between January 1995 and January 30, 1998, funded by dividends from its subsidiaries and its lines of credit.

Edison International's cash flow coverage of dividends for 1997 was 5.2 times compared to 5.0 times in 1996 and 4.7 times in 1995. Edison International's dividend payout ratio for 1997 was 57%.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $2.1 billion in 1997, $2.2 billion in 1996 and $2.1 billion in 1995. Cash from operations exceeded capital requirements for all years presented.

Cash Flows from Financing Activities

At December 31, 1997, Edison International and its subsidiaries had $3.1 billion of borrowing capacity available under lines of credit totaling $3.6 billion. SCE had available lines of credit of $1.8 billion, with $1.3 billion for general purpose short-term debt and $500 million for the long-term refinancing of its variable-rate pollution-control bonds. The parent company had available lines of credit totaling $1.0 billion. The nonutility companies had lines of credit of $800 million available to finance general cash requirements. Edison International's unsecured lines of credit are at negotiated or bank index rates with various expiration dates. The majority have five-year terms.

SCE's short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements. EME uses available credit lines mainly for construction projects until long-term construction or project loans are secured. Long-term debt is used mainly to finance capital expenditures. SCE's external financings are influenced by market conditions and other factors, including limitations imposed by its articles of incorporation and trust indenture. As of December 31, 1997, SCE could issue approximately $10.4 billion of additional first and refunding mortgage bonds and $5.3 billion of preferred stock at current interest and dividend rates.

EME owns, through a wholly owned subsidiary, 50% of the Brooklyn Navy Yard project. On December 17, 1997, the Brooklyn Navy Yard project partnership completed a $407 million permanent, nonrecourse financing for the project.

In February 1997, the contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard Cogeneration Partners, L.P. (BNY) for damages in the amount of $137 million. In addition to defending this action, BNY has filed an action against the contractor in New York State Court asserting general monetary claims in excess of $13 million arising out of the turnkey agreement. EME agreed to indemnify the partnership and its partner from all claims and costs arising from or in connection with the contractor litigation, which indemnity has been assigned to the lenders. Edison International believes that the outcome of this litigation will not materially affect its results of operations or financial position.

In April 1997, EME completed financing and commenced construction of the Doga project, a 180-megawatt, gas-powered power plant near Istanbul, Turkey. A wholly owned subsidiary of EME owns 80% of this project. In connection with the financing, EME has guaranteed $21 million in equity contributions and will continue making equity contributions until commercial operation begins, which is scheduled for 1999.

In May 1997, Edison Capital closed its largest infrastructure transaction in recent years by entering into a cross-border lease transaction in the Eems Power Station located in the Netherlands. This transaction was valued at $188 million. The Eems Power Station is a new, five unit (335 MW each) gas-fired, combined-cycle power plant. It is operated by EPON, the largest power generating company in the Netherlands. Edison Capital also acquired an interest in the electric power transmission system in South Australia. This cross-border lease transaction was valued at $161 million.

EME has firm commitments of $295 million to make equity and other contributions, primarily for the Paiton project in Indonesia, the ISAB project in Italy, and the Doga project in Turkey. EME also has contingent obligations to make additional contributions of $181 million, primarily for equity support guarantees related to Paiton.

EME may incur additional obligations to make equity and other contributions to projects in the future. EME believes it will have sufficient liquidity to meet these equity requirements from cash provided by operating activities, proceeds from the repayment of loans to energy projects and funds available from EME's revolving line of credit.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1997, SCE had the capacity to pay $1.4 billion in additional dividends and continue to maintain its authorized capital structure. These restrictions are not expected to affect Edison International's ability to meet its cash obligations.

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

The rate reduction notes have maturities ranging from one to 10 years, and bear interest at rates ranging from 5.98% to 6.42%. The rate reduction notes are secured solely by the transition property and certain other assets of the SPE, and there is no recourse to SCE or Edison International.

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

Cash Flows from Investing Activities

The primary uses of cash for investing activities are additions to property and plant, the nonutilities' investments in partnerships and unconsolidated subsidiaries, and funding of nuclear decommissioning trusts. Decommissioning costs are accrued and recovered in rates over the term of each nuclear generating facility's operating license through charges to depreciation expense. SCE estimates that it will spend approximately $12.7 billion between 2013 – 2070 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning costs ($2.1 billion), escalated using a 6.65% annual rate. These costs are expected to be funded from independent decommissioning trusts which receive SCE contributions of approximately $100 million per year until decommissioning begins.

Cash used for the nonutility subsidiaries' investing activities was $375 million in 1997, $409 million in 1996 and $1.2 billion in 1995.

Market Risk Exposures

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

SCE has hedged a portion of its exposure to increases in natural gas prices. Increases in natural gas prices tend to increase the price of electricity purchased from the power exchange (PX). SCE's exposure is also limited by regulatory mechanisms that protect SCE from much of the risk arising from high electricity prices.

Changes in interest rates, electricity pool pricing and fluctuations in foreign currency exchange rates can have a significant impact on EME's results of operations. EME has mitigated the risk of interest rate fluctuations by arranging for fixed rate or variable rate financing with interest rate swaps or other hedging mechanisms for the majority of its project financings. As a result of interest rate hedging mechanisms, interest expense increased $21 million in 1997, $6 million in 1996 and $7 million in 1995. The maturity dates of several of EME's interest rate swap agreements do not correspond to the term of the underlying debt. EME does not believe that interest rate fluctuations will have a material adverse effect on its results of operations or financial position.

Projects in the United Kingdom sell their electrical energy and capacity through a centralized electricity pool, which establishes a half-hourly clearing price for electrical energy. The pool price is extremely volatile, and can vary by a factor of ten or more over the course of a few hours due to large differentials in demand according to the time of day. First Hydro mitigates a portion of the market risk of the pool by entering into contracts for differences (electricity rate swap agreements), related to either the selling or purchase price of power, where a contract specifies a price at which the electricity will be traded, and the parties to the agreements make payments, calculated based on the difference between the price in the contract and the half-hourly clearing price for the element of power under contract. These contracts can be sold in two structures: one-way contracts, where a specified monthly amount is received in advance and difference payments are made when the pool price is above the price specified in the contract, and two-way contracts, where the counterparty pays First Hydro when the pool price is below the contract price instead of a specified monthly amount. These contracts act as a means of stabilizing production revenue or purchasing costs by removing an element of First Hydro's net exposure to pool price volatility. First Hydro's electric revenue increased by $37 million and decreased by $5 million for the year ended December 31, 1997, and 1996, respectively, as a result of electricity rate swap agreements.

Loy Yang B sells its electrical energy through a centralized electricity pool, which provides for a system of generator bidding, central dispatch and a settlements system based on a clearing market for each half-hour of every day. The Victorian Power Exchange, operator and administrator of the pool, determines a system marginal price each half-hour. To mitigate the exposure to price volatility of the electricity traded in the pool, Loy Yang B has entered into a number of financial hedges. From May 8, 1997, to December 31, 2000, approximately 53% to 64% of the plant output sold is hedged under vesting contracts, with the remainder of the plant capacity hedged under the state hedge described below. Vesting contracts were put into place by the State of Victoria, between each generator and each distributor, prior to the privatization of electric power distributors in order to provide more predictable pricing for those electricity customers that were unable to choose their electricity retailer. Vesting contracts set base strike prices at which the electricity will be traded, and the parties to the agreement make payments, calculated based on the difference between the price in the contract and the half-hourly pool clearing price for the element of power under contract. These contracts can be sold as one-way or two-way contracts which are structured similar to the electricity rate swap agreements described above. These contracts are accounted for as electricity rate swap agreements. The state hedge is a long-term contractual arrangement based upon a fixed price commencing May 8, 1997, and terminating October 31, 2016. The State guarantees the State Electricity Commission of Victoria's obligations under the state hedge. Loy Yang B's electric revenue was increased by $59 million for the year ended December 31, 1997, as a result of hedging contract arrangements. As EME continues to expand into foreign markets, fluctuations in foreign currency exchange rates can affect the amount of its equity contributions to, distributions from, and results of operations of its foreign projects. At times, EME has hedged a portion of its current exposure to fluctuations in foreign exchange rates where it deems appropriate through financial derivatives, offsetting obligations denominated in foreign currencies, and indexing underlying project agreements to U.S. dollars or other indices reasonably expected to correlate with foreign exchange movements. Various statistical forecasting techniques are used to help assess foreign exchange risk and the probabilities of various outcomes. There can be no assurance, however, that fluctuations in exchange rates will be fully offset by hedges or that currency movements and the relationship between certain macroeconomic variables will behave in a manner that is consistent with historical or forecasted relationships.

Construction on the two-unit Paiton project is approximately 85% complete, and commercial operation is expected in the first half of 1999. The tariff is higher in the early years and steps down over time, and the tariff for the Paiton project includes infrastructure to be used in common by other units at the Paiton complex. The plant's output is fully contracted with the state-owned electricity company for payment in U.S. dollars. The projected rate of growth of the Indonesian economy and the exchange rate of Indonesian Rupiah into U.S. dollars have deteriorated significantly since the Paiton project was contracted, approved and financed with substantial finance and insurance support from the Export-Import Bank of the United States, The Export-Import Bank of Japan, the U.S. Overseas Private Investment Corporation and the Ministry of International Trade and Industry of Japan. The Paiton project's senior debt ratings have been reduced from investment grade to speculative grade based on the rating agencies' perceived increased risk that the state-owned electricity company might not be able to honor the electricity sales contract with Paiton. A Presidential decree has deemed some power plants, but not including the Paiton project, subject to review, postponement or cancellation. EME continues to monitor the situation closely.

A 10% increase in market interest rates would result in a $29 million increase in the fair value of Edison International's interest rate hedge agreements. A 10% decrease in market interest rates would result in a $30 million decline in the fair market value of interest rate hedge agreements. A 10% increase in pool prices would result in a $97 million decrease in the fair value of electricity rate swap agreements. A 10% decrease in pool prices would result in a $97 million increase in the fair value of electricity rate swaps. A 10% increase in natural gas prices would result in a $26 million increase in the fair market value of gas call options. A 10% decrease in natural gas prices would result in a $17 million decline in the fair market value of gas call options. A 10% change in market rates is expected to have an immaterial effect on Edison International's other financial instruments.

Projected Capital Requirements

Edison International's projected construction expenditures for the next five years are: 1998—$1.1 billion; 1999—$807 million; 2000—$763 million; 2001—$721 million; and 2002—$671 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 1998—$848 million; 1999—$670 million; 2000—$719 million; 2001—$728 million; and 2002—$635 million.

Preferred stock redemption requirements for the next five years are: 1998 through 2001—zero and 2002—$105 million.

Regulatory Matters

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

In 1998, SCE's revenue will be affected by various mechanisms depending on the utility operation. Revenue related to distribution operations will be determined through a performance-based rate-making mechanism (PBR) (see discussion in Competitive Environment — PBR) and the distribution assets will have the opportunity to earn a CPUC-authorized 9.49% return. Until the independent system operator (ISO) begins operation, transmission revenue will be determined by the same mechanism as distribution operations. After that time, transmission revenue will be determined through FERC-authorized rates and transmission assets will earn a 9.43% return. These rates are subject to refund. See discussions in the Competitive Environment — Rate-setting and FERC Restructuring Decision sections.

Revenue from generation-related operations will be determined through the competition transition charge (CTC) mechanism, nuclear rate-making agreements and the competitive market in 1998. Revenue related to fossil and hydroelectric generation operations will be recovered from two sources. The portion that is made uneconomic by electric industry restructuring will be determined through the CTC mechanism. The portion that is economic will be recovered through the PX mechanism. In 1998, fossil and hydroelectric generation assets will earn a 7.22% return. A more detailed discussion is in Competitive Environment — CTC.

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

The changes in revenue from the regulatory mechanisms discussed above, excluding the effects of other rate actions, are expected to have a minimal impact on 1998 earnings. However, the issuance of the rate reduction notes in December 1997, which enables the repurchase of debt and equity, will have a negative impact on 1998 earnings of approximately $97 million. The impact on earnings per share will be mitigated due to the repurchase of common stock from the rate reduction note proceeds.

In 1994, SCE filed its testimony in the non-Qualifying Facilities (QF) phase of the 1994 Energy Cost Adjustment Clause proceeding. In 1995, the CPUC's Office of Ratepayer Advocates (ORA) filed its report on the reasonableness of SCE's gas supply costs for both the 1993 and 1994 record periods. The report recommended a disallowance of $13 million for excessive costs incurred from November 1993 through March 1994 associated with SCE's Canadian gas purchase and supply contracts. The report requested that the CPUC defer finding SCE's Canadian supply and transportation agreements reasonable for the duration of their terms and that the costs under these contracts be reviewed on a yearly basis. In 1996, the ORA issued its report for the 1995 record period recommending a $38 million disallowance for excessive costs incurred from April 1994 through March 1995. Both proposed disallowances were later consolidated into one proceeding. On December 3, 1997, the CPUC approved a settlement agreement between SCE and the ORA on this and any future issues, which will result in a $61 million (including interest) refund to SCE's customers. This refund is fully reflected in the financial statements and will be made in first quarter 1998.

In 1991, SCE filed its testimony in the QF phase of the 1991 Energy Cost Adjustment Clause proceeding. In 1993, the ORA filed its report on the reasonableness of SCE's QF contracts and alleged that SCE had imprudently renegotiated a QF contract with the Mojave Cogeneration Company. The report recommended a disallowance of $32 million (1993 net present value) over the contract's 20-year life. Subsequently, SCE and the ORA reached a settlement where SCE agreed to a one-time reduction to its energy cost adjustment clause balancing account of $14 million plus interest. In October 1996, the CPUC approved the settlement agreement, subject to SCE and the ORA accepting certain conditions concerning the way the $14 million payment would be reflected in rates. After reviewing the decision, SCE declined to accept the condition proposed by the CPUC and in November 1996 filed an application for rehearing. In February 1997, the CPUC denied SCE's application. Because SCE and the ORA were unable to finalize their settlement, hearings on the ORA's disallowance recommendations were held in June 1997. During the hearings, the ORA presented testimony to update its assessment of ratepayer harm, which it now estimates to be $45 million (1997 net present value) over the contract's life. In November 1997, a CPUC administrative law judge (ALJ) issued a proposed decision which would adopt the ORA's $45 million disallowance. In January 1998, the CPUC withdrew the ALJ's proposed decision pending oral arguments. Oral arguments were heard on February 4, 1998, at which time SCE requested an alternate proposed decision be issued. SCE expects this matter to be returned to the CPUC's agenda in the near future and a final decision to be issued during second quarter 1998. SCE cannot predict the final outcome of this matter but does not believe it will materially affect its results of operations.

COMPETITIVE ENVIRONMENT

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

California Electric Utility Restructuring

Restructuring Legislation — In September 1996, the State of California enacted legislation to provide a transition to a competitive market structure. The legislation substantially adopted the CPUC's December 1995 restructuring decision by addressing stranded-cost recovery for utilities and providing a certain cost-recovery time period for the transition costs associated with utility-owned generation-related assets. Transition costs related to power-purchase contracts would be recovered through the terms of their contracts while most of the remaining transition costs would be recovered through 2001. The legislation also included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which would allow SCE to reduce rates by at least 10% to these customers, beginning January 1, 1998. The financing would occur with securities issued by the California Infrastructure and Economic Development Bank, or an entity approved by the Bank. The legislation included a rate freeze for all other customers, including large commercial and industrial customers, as well as provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement during the 1998-2001 transition period. In addition, the legislation mandated the implementation of the CTC that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the legislation contained provisions for the recovery (through 2006) of reasonable employee-related transition costs, incurred and projected, for retraining, severance, early retirement, outplacement and related expenses.

Rate Reduction Notes — In May 1997, SCE filed an application with the CPUC requesting approval of the issuance of an aggregate amount of up to $3 billion of rate reduction notes in one or more series or classes and a 10% rate reduction for the period from January 1, 1998, through March 31, 2002. At the same time, SCE filed an application with the California Infrastructure and Economic Development Bank for approval to issue the notes. Residential and small commercial customers will repay the notes over the expected 10-year term through non-bypassable charges based on electricity consumption. In December 1997, after receiving approval from both the CPUC and the Infrastructure Bank, a limited liability company created by SCE issued approximately $2.5 billion of these notes. For further details, see the discussion in Cash Flows from Financing Activities.

CPUC Restructuring Decision — The CPUC's December 1995 decision on restructuring California's electric utility industry started the transition to a new market structure, which is expected to provide competition and customer choice and is scheduled to begin March 31, 1998. Key elements of the CPUC's restructuring decision included: creation of the PX and ISO; availability of direct customer access and customer choice; PBR for those utility services not subject to competition; voluntary divestiture of at least 50% of utilities' gas-fueled generation, and implementation of the CTC.

Rate-setting — In December 1996, SCE filed a more comprehensive plan (elaborating on its July 1996 filing related to the conceptual aspects of separating costs as requested by CPUC and FERC directives) for the functional unbundling of its rates for electric service, beginning January 1, 1998. In response to CPUC and FERC orders, as well as the new restructuring legislation, this filing addressed the implementation-level detail for the functional unbundling of rates into separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The transmission component of this rate unbundling process was addressed at the FERC through a March 1997 filing. In December 1997, the FERC approved these rates, subject to refund, to be effective on the date the ISO begins operation. CPUC hearings on SCE's rate unbundling (also known as rate-setting) plan were concluded in April 1997. In August 1997, the CPUC issued a decision which adopted the methodology for determining CTC residually (see CTC discussion below) and adopted SCE's revenue requirement components for public benefit programs and nuclear decommissioning. The decision also adjusted SCE's proposed distribution revenue requirement by reallocating $76 million of the amount annually to other functions such as generation and transmission. Under the decision, SCE will be able to recover most of the reallocated amount through market revenue, other rate-making mechanisms after petitioning the CPUC to modify its prior decisions, or another review process later in its divestiture proceeding.

PX and ISO — In April 1996, SCE, Pacific Gas & Electric Company and San Diego Gas & Electric Company filed a proposal with the FERC regarding the creation of the PX and the ISO. In November 1996, the FERC conditionally accepted the proposal and directed the three utilities, the ISO, and the PX to file more specific information. The filing was made in March 1997, and included SCE's proposed transmission revenue requirement. On October 29, 1997, the FERC gave conditional, interim authorization for operation of the PX and ISO to begin on January 1, 1998. The FERC stated it would closely monitor the PX and ISO, require further studies and make modifications, where necessary. A comprehensive review will be performed by the FERC after three years of operation of the PX and ISO. On December 22, 1997, the PX and ISO governing boards announced a delay in the planned start-up of the PX and ISO due to insufficient testing of operational, settlement and billing systems. The PX and ISO are now expected to begin operation by March 31, 1998.

In July 1996, the three utilities jointly filed an application with the CPUC requesting approval to establish a restructuring trust which would obtain loans up to $250 million for the development of the ISO and PX through January 1, 1998. The loans are backed by utility guarantees; SCE's share was 45%, or $113 million. In August 1996, the CPUC issued an interim order establishing the restructuring trust and the funding level of $250 million, which has been used to build the hardware and software systems for the ISO and PX. The ISO and PX will repay the trust's loans and recover funds from future ISO and PX customers. In November 1997, the CPUC approved a petition jointly filed by the three utilities which requested an increase in the loan guarantees from $250 million to $300 million; SCE's share of this new total is $135 million. In December 1997, the CPUC approved a remaining item with respect to the petition which requested that the one-time restructuring implementation charge, to be paid to the PX by the utilities, be deemed a non-bypassable charge to be recovered from all retail customers. The amount of the PX charge is $85 million; SCE's share is 45%, or $38 million.

Direct Customer Access — In May 1997, the CPUC issued a decision describing how all California investor-owned-utility customers will be able to choose who will provide them with electric generation service beginning January 1, 1998. On December 30, 1997, the CPUC issued a decision delaying direct access until March 31, 1998, due to operational delays in the start-up of the PX and ISO. On this date, customers will be able to choose to remain utility customers with bundled electric service from SCE (which will purchase its power through the PX), or choose direct access, which means the customer can contract directly with either independent power producers or retail electric service providers such as power brokers, marketers and aggregators. Additionally, all investor-owned-utility customers must pay the CTC whether or not they choose to buy power through SCE. Electric utilities will continue to provide the core distribution service of delivering energy through its distribution system regardless of a customer's choice of electricity supplier. The CPUC will continue to regulate the prices and service obligations related to distribution services. If the new competitive market cannot accommodate the volume of direct access transactions, the CPUC could implement a contingency plan. However, the CPUC believes it is likely that interest in and migration to direct access will be gradual.

Revenue Cycle Services — A decision issued by the CPUC in May 1997, introduces customer choice to metering, billing and related services (referred to as revenue cycle services) that are now provided by California's investor-owned utilities. Under this revenue cycle services unbundling decision, beginning in January 1998, direct access customers may choose to have either SCE or their electric generation service provider render consolidated (energy and distribution) bills, or they may choose to have separate billings from each service provider. However, not all electric generation service providers will necessarily offer each billing option. In addition, beginning in January 1998, customers with maximum demand above 20 kW (primarily industrial and large commercial) can choose SCE or any other supplier to provide their metering service. All other customers will have this option beginning in January 1999. In determining whether any credit should be provided by the utility to firms providing customers with revenue cycle services, and the amount of any such credit, the CPUC has indicated that it is appropriate to net the cost incurred by the utility and the cost avoided by the utility as a result of such services being provided by the other firm rather than by the utility. The unbundling of revenue cycle services will expose SCE to the possible loss of revenue, higher stranded costs and a reduction in revenue security.

PBR — In 1993, SCE filed for a PBR mechanism to determine most of its revenue (excluding fuel). The filing was subsequently divided between transmission and distribution (T&D) and power generation.

In September 1996, the CPUC adopted a non-generation or T&D PBR mechanism for SCE which began on January 1, 1997. According to the CPUC, beginning in 1998 (coincident with the initiation of the competitive market), the transmission portion is to be separated from non-generation PBR and subject to ratemaking under the rules of the FERC. The distribution-only PBR will extend through December 2001. Key elements of the non-generation PBR include: T&D rates indexed for inflation based on the Consumer Price Index less a productivity factor; elimination of the kilowatt-hour sales adjustment; adjustments for cost changes that are not within SCE's control; a cost of capital trigger mechanism based on changes in a bond index; standards for service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from T&D operations.

With the CPUC's 1995 restructuring decision and the passage of restructuring legislation in 1996, the majority of power generation ratemaking (primarily fossil-fueled and nuclear) was assigned to other mechanisms. In April 1997, a CPUC interim order determined that the proposed structure of the fossil-fueled plants' must-run contracts were under the FERC's jurisdiction. On October 31, 1997, SCE filed must-run tariff schedules with the FERC covering its six ISO-designated must-run plants. In the meantime, SCE is pursuing the divestiture of these plants (see Divestiture discussion below) and might not ever itself provide service under these FERC tariff schedules.

In December 1997, the CPUC adopted a PBR-type ratemaking mechanism for SCE's hydroelectric plants. The mechanism sets the hydroelectric revenue requirement in 1998 and establishes a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurs first. The mechanism provides that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement be credited against the costs to transition to a competitive market (see CTC discussion below).

Divestiture — In November 1996, SCE filed an application with the CPUC to voluntarily divest, by auction, all 12 of its oil- and gas-fueled generation plants. This application builds on SCE's March 1996 plan which outlined how SCE proposed to divest 50% of these assets. Under the new proposal, SCE would continue to operate and maintain the divested power plants for at least two years following their sale, as mandated by the restructuring legislation enacted in September 1996. In addition, SCE would offer workforce transition programs to those employees who may be impacted by divestiture-related job reductions. SCE's proposal is contingent on the overall electric industry restructuring implementation process continuing on a satisfactory path. In September 1997, the CPUC approved SCE's proposal to auction the 12 plants.

On December 1, 1997, SCE filed a compliance filing with the CPUC stating that it had sold 10 plants. On December 16, 1997, the CPUC approved the sale of the 10 plants. On February 6, 1998, SCE filed a compliance filing with the CPUC regarding the sale of an 11th plant. CPUC approval of the sale is expected before March 31, 1998. The total sales price of the 11 plants is $1.1 billion, or 2.16 times their combined book value of $531 million. Net proceeds of the sales will be used to reduce stranded costs, which otherwise were expected to be collected through the CTC mechanism. The transfer of ownership of the 11 plants is expected to occur shortly before the start of the new competitive market, which the PX and ISO currently expect to occur on March 31, 1998. The sale and CPUC approval of the single remaining plant is expected to be completed in early 1998.

CTC — Recovery of costs to transition to a competitive market is being implemented through a non-bypassable CTC. This charge applies to all customers who were using or began using utility services on or after the CPUC's December 20, 1995, decision date. In August 1996, in compliance with the CPUC's restructuring decision, SCE filed its application to estimate its 1998 transition costs. In October 1996, SCE amended its transition cost filing to reflect the effects of the legislation enacted in September 1996. Under the rate freeze codified in the legislation, the CTC will be determined residually (i.e., after subtracting other cost components for the PX, T&D, nuclear decommissioning and public benefit programs). Nevertheless, the CPUC directed that the amended application provide estimates of SCE's potential transition costs from 1998 through 2030. SCE provided two estimates between approximately $13.1 billion (1998 net present value) assuming the fossil plants have a market value equal to their net book value, and $13.8 billion (1998 net present value) assuming the fossil plants have no market value. These estimates are based on incurred costs, forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. The potential transition costs are comprised of: $7.5 billion from SCE's QF contracts, which are the direct result of prior legislative and regulatory mandates; and $5.6 billion to $6.3 billion from costs pertaining to certain generating plants (successful completion of the sale of SCE's gas-fired generating plants would reduce this estimate of transition costs for SCE-owned generation to less than $5 billion) and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre Units 2 and 3 and the Palo Verde units (as discussed in Regulatory Matters), and certain other costs. In February 1997, SCE filed an update to the CTC filing to reflect approval by the CPUC of settlements regarding ratemaking for SCE's share of Palo Verde and the buyout of a power purchase agreement, as well as other minor data updates. No substantive changes in the total CTC estimates were included. This issue has been separated into two phases; Phase 1 addresses the rate-making issues and Phase 2 the quantification issues.

A decision on Phase 1 was issued in June 1997, which, among other things, required the establishment of a transition cost balancing account and annual transition cost proceedings, set a market rate forecast for 1998 transition costs, and required that generation-related regulatory assets be amortized ratably over a 48-month period. Hearings on Phase 2 were held in May and June 1997 and a final decision was issued on November 19, 1997. The Phase 2 decision established the calculation methodologies and procedures for SCE to collect its transition costs from 1998 through the end of the rate freeze. The Phase 2 decision also reduced SCE's authorized rate of return on certain assets eligible for transition cost recovery (primarily fossil- and hydroelectric-generation related assets) beginning July 1997, five months earlier than anticipated. The decision, excluding the effects of other rate actions, had a negative impact on 1997 earnings of approximately 4¢ per share. SCE has filed an application for rehearing on the 1997 rate of return issue.

Accounting for Generation-Related Assets — If the CPUC's electric industry restructuring plan is implemented as outlined above, SCE would be allowed to recover its CTC through non-bypassable charges to its distribution customers (although its investment in certain generation assets would be subject to a lower authorized rate of return).

As previously reported, from November 1996 to July 1997, SCE and the other major California electric utilities were engaged in discussions with the Securities and Exchange Commission staff regarding the proper application of regulatory accounting standards in light of the electric industry restructuring legislation enacted by the State of California in September 1996 and the CPUC's electric industry restructuring plan. This issue was placed on the agenda of the Financial Accounting Standards Board's Emerging Issues Task Force (EITF) during April 1997 and a final consensus was reached at the July EITF meeting. During the third quarter of 1997, SCE implemented the EITF consensus and discontinued application of accounting principles for rate-regulated enterprises for its investment in generation facilities.

However, implementation of the EITF consensus did not require SCE to write off any of its generation-related assets, including regulatory assets of approximately $600 million at December 31, 1997. SCE has retained these assets on its balance sheet because the legislation and restructuring plan referred to above make probable their recovery through a non-bypassable CTC to distribution customers. These regulatory assets relate primarily to the recovery of accelerated income tax benefits previously flowed through to customers, purchased power contract termination payments, unamortized losses on reacquired debt, and the recovery of amounts deferred under the Palo Verde rate phase-in plan. The consensus reached by the EITF also permits the recording of new generation-related regulatory assets during the transition period that are probable of recovery through the CTC mechanism.

If during the transition period events were to occur that made the recovery of these generation-related regulatory assets no longer probable, SCE would be required to write off the remaining balance of such assets as a one-time, non-cash charge against earnings. If such a write-off were to be required, SCE believes that it should not affect the recovery of stranded costs provided for in the legislation and restructuring plan.

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

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

FERC Restructuring Decision

In April 1996, the FERC issued its decision on stranded-cost recovery and open access transmission, effective July 1996. The decision, reaffirmed by the FERC in its March and November 1997 orders, requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with increased access to transmission facilities for wholesale transactions and also establishes information requirements for the transmission utility. The decision also provides utilities with the opportunity to recover stranded costs associated with existing wholesale customers, retail-turned-wholesale customers and retail wheeling when the state regulatory body does not have authority to address retail stranded costs. Even though the CPUC is currently addressing stranded-cost recovery through the CTC proceedings, the FERC has also asserted primary jurisdiction over the recovery of stranded costs associated with retail-turned-wholesale customers, such as a new municipal electric system or a municipal annexation. However, the FERC did clarify that it does not intend to prevent or interfere with a state's authority and that it has discretion to defer to a state stranded-cost-calculation method. In January 1997, the FERC accepted the open access transmission tariff SCE filed in compliance with the April 1996 decision. The rates included in the tariff are being collected subject to refund. In May 1997, SCE filed a revised open access tariff to reflect the few revisions set forth in the March 1997 order. The open access transmission tariff will be terminated on the date the ISO begins operation.

Environmental Protection

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

As further discussed in Note 10 to the Consolidated Financial Statements, Edison International records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site. Unless there is a probable amount, Edison International records the lower end of this range of costs.

In connection with the issuance of the San Onofre Units 2 and 3 operating permits, SCE reached agreement with the California Coastal Commission in 1991 to restore certain marine mitigation sites. The restorations include two sites: designated wetlands and the construction of an artificial kelp reef off the California coast. After SCE requested certain modifications to the agreement, the Coastal Commission issued a final ruling in April 1997 to reduce the scope of remediations. SCE elected to pay for the costs of marine mitigation in lieu of placing the funds into a trust. Rate recovery of these costs is occurring through the San Onofre incentive pricing plan.

Edison International's recorded estimated minimum liability to remediate its 51 identified sites is $178 million, which includes $75 million for the two sites discussed above. One of SCE's sites, a former pole-treating facility, is considered a federal Superfund site and represents 42% of Edison International's recorded liability. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $246 million. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental-cleanup costs at 41 of its sites, representing $91 million of Edison International's recorded liability, through an incentive mechanism. Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $153 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates. This amount includes $60 million of marine mitigation costs remaining to be recovered through the San Onofre incentive pricing plan.

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

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $10 million. Recorded costs for 1997 were $10 million.

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

The 1990 federal Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). The act also calls for a study to determine if additional regulations are needed to reduce regional haze in the southwestern U.S. In addition, another study is in progress to determine the specific impact of air contaminant emissions from the Mohave Coal Generating Station on visibility in Grand Canyon National Park. The potential effect of these studies on sulfur dioxide emissions regulations for Mohave is unknown.

Edison International's projected capital expenditures to protect the environment are $820 million for the 1998 – 2002 period, mainly for aesthetics treatment, including undergrounding certain transmission and distribution lines.

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

San Onofre Steam Generator Tubes

The San Onofre Units 2 and 3 steam generators have performed relatively well through the first 15 years of operation, with low rates of ongoing steam generator tube degradation. However, during the Unit 2 scheduled refueling and inspection outage, which was completed in Spring 1997, an increased rate of tube degradation was identified, which resulted in the removal of more tubes from service than had been expected. The steam generator design allows for the removal of up to 10% of the tubes before the rating capacity of the unit must be reduced. As a result of the increased degradation, a mid-cycle inspection outage will be conducted in early 1998 for Unit 2.

During Unit 3's refueling outage, which was completed in July 1997, inspections of structural supports for steam generator tubes identified several areas where the thickness of the supports had been reduced, apparently by erosion during normal plant operation. As a result, a mid-cycle inspection outage is planned for early 1998. However, during Unit 2's Spring 1997 inspection outage, similar tube supports showed no signs of such erosion.

Proposed New Accounting Standard

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

Year 2000 Issue

Many of SCE's existing computer systems identify a year by only two digits instead of four. If not corrected, these programs could fail or create erroneous results when the new century begins. This situation has been referred to generally as the Year 2000 Issue.

SCE has developed plans and is addressing the programming changes that it has determined are necessary in order for its computer systems to function properly beginning in 2000. Remediation of SCE's key financial systems for the Year 2000 Issue was completed in 1997. SCE's informational and operational systems have been assessed, and detailed plans have been developed to address modifications required to be completed, tested and operational by December 31, 1999. Preliminary estimates of the costs to complete these modifications, including the cost of new hardware and software application modifications, range from $55 million to $80 million, about half of which are expected to be capital costs. Current rate levels for providing electric service should be sufficient to provide funding for these modifications. Remediation of existing critical systems is expected to be 75% complete by the end of 1998. SCE expects its Year 2000 date conversion project to be completed on a timely basis, with no material adverse impact to its results of operations or financial position.

SCE's Year 2000 date conversion project includes an assessment of critical interfaces with the computer systems of others and it does not expect a material adverse effect on its operating and business functions from the Year 2000 Issue.

Quarterly Financial Data

(Unaudited)

			1997		
In millions, except per-share amounts	*Total*	*Fourth*	*Third*	*Second*	*First*
Operating revenue	$ 9,235	$ 2,329	$ 2,738	$ 2,167	$ 2,001
Operating income	1,498	342	470	329	357
Net income	700	139	277	139	145
Per share:					
Basic earnings	1.75	.37	.70	.34	.35
Diluted earnings	1.73	.36	.70	.34	.34
Dividends declared	1.00	.25	.25	.25	.25
Common stock prices:					
High	$27 13/16	$27 11/16	$ 27 1/4	$ 25 3/8	$ 23 1/8
Low	19 1/2	24 11/16	24	20 1/4	19 1/2
Close	27 3/16	27 3/16	25 1/4	24 7/8	22 1/2

			1996		
In millions, except per-share amounts	*Total*	*Fourth*	*Third*	*Second*	*First*
Operating revenue	$ 8,545	$ 2,195	$ 2,568	$ 1,814	$ 1,968
Operating income	1,478	328	468	332	350
Net income	717	117	277	156	167
Per share:					
Basic earnings	1.64	.27	.63	.35	.38
Diluted earnings	1.63	.27	.63	.35	.37
Dividends declared	1.00	.25	.25	.25	.25
Common stock prices:					
High	$ 20 3/8	$ 20 3/8	$ 18 1/4	$ 17 5/8	$ 18 3/8
Low	15 1/8	17 1/4	15 1/8	15 3/8	16 5/8
Close	19 7/8	19 7/8	17 7/8	17 5/8	17 1/4

Responsibility for Financial Reporting

The management of Edison International is responsible for the integrity and objectivity of the accompanying financial statements. The statements have been prepared in accordance with generally accepted accounting principles applied on a consistent basis and are based, in part, on management estimates and judgment.

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

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

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

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

Richard K. Bushey
Richard K. Bushey
Vice President and Controller

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

January 30, 1998

Report of Independent Public Accountants

To the Shareholders and the Board of Directors, Edison International:

We have audited the accompanying consolidated balance sheets of Edison International (a California corporation) and its subsidiaries as of December 31, 1997, and 1996, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1997. These financial statements are the responsibility of Edison International's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Edison International and its subsidiaries as of December 31, 1997, and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997, in conformity with generally accepted accounting principles.

Arthur Andersen LLP

Arthur Andersen LLP
Los Angeles, California

January 30, 1998

Consolidated Statements of Income

In millions, except per-share amounts Year ended December 31,	1997	1996	1995
Electric utility revenue	$ 7,953	$ 7,583	$ 7,873
Diversified operations	1,282	962	532
Total operating revenue	9,235	8,545	8,405
Fuel	1,074	768	694
Purchased power	2,854	2,706	2,582
Provisions for regulatory adjustment clauses — net	(411)	(226)	230
Other operating expenses	1,781	1,555	1,411
Maintenance	406	331	359
Depreciation and decommissioning	1,362	1,173	1,014
Income taxes	537	563	528
Property and other taxes	134	197	210
Total operating expenses	7,737	7,067	7,028
Operating income	1,498	1,478	1,377
Provision for rate phase-in plan	(48)	(84)	(122)
Allowance for equity funds used during construction	8	16	19
Interest and dividend income	85	63	65
Minority interest	(39)	(70)	(48)
Other nonoperating income (deductions) — net	(62)	(13)	41
Total other income (deductions) — net	(56)	(88)	(45)
Income before interest and other expenses	1,442	1,390	1,332
Interest on long-term debt	584	604	539
Other interest expense	139	90	81
Allowance for borrowed funds used during construction	(9)	(10)	(14)
Capitalized interest	(15)	(58)	(60)
Dividends on subsidiary preferred securities	43	47	47
Total interest and other expenses — net	742	673	593
Net income	$ 700	$ 717	$ 739
Weighted-average shares of common stock outstanding	400	437	446
Basic earnings per share	$ 1.75	$ 1.64	$ 1.66
Diluted earnings per share	$ 1.73	$ 1.63	$ 1.65

Consolidated Statements of Retained Earnings

In millions, except per-share amounts Year ended December 31,	1997	1996	1995
Balance at beginning of year	$ 3,753	$ 3,700	$ 3,452
Net income	700	717	739
Dividends declared on common stock	(395)	(435)	(446)
Stock repurchase and retirement	(882)	(229)	(45)
Balance at end of year	$ 3,176	$ 3,753	$ 3,700
Dividends declared per common share	$ 1.00	$ 1.00	$ 1.00

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

Consolidated Balance Sheets

In millions	*December 31,*	*1997*	*1996*
ASSETS			
Transmission and distribution:			
Utility plant, at original cost, subject to cost-based rate regulation		$11,213	$10,973
Accumulated provision for depreciation		(5,574)	(5,129)
Construction work in progress		493	462
		6,132	6,306
Generation:			
Utility plant, at original cost, not subject to cost-based rate regulation		9,522	9,427
Accumulated provision for depreciation and decommissioning		(4,970)	(4,302)
Construction work in progress		100	95
Nuclear fuel, at amortized cost		155	177
		4,807	5,397
Total utility plant		10,939	11,703
Nonutility property — less accumulated provision for depreciation of $238 and $203 at respective dates		3,178	3,570
Nuclear decommissioning trusts		1,831	1,486
Investments in partnerships and unconsolidated subsidiaries		1,408	1,372
Investments in leveraged leases		960	584
Other investments		194	104
Total other property and investments		7,571	7,116
Cash and equivalents		1,907	897
Receivables, including unbilled revenue, less allowances of $27 and $26 for uncollectible accounts at respective dates		1,077	1,095
Fuel inventory		58	72
Materials and supplies, at average cost		133	154
Accumulated deferred income taxes — net		123	240
Regulatory balancing accounts — net		193	—
Prepayments and other current assets		106	114
Total current assets		3,597	2,572
Unamortized debt issuance and reacquisition expense		359	347
Income tax-related deferred charges		1,544	1,741
Other deferred charges		1,091	1,080
Total deferred charges		2,994	3,168
Total assets		$25,101	$24,559

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

In millions, except share amounts December 31,	1997	1996
CAPITALIZATION AND LIABILITIES		
Common shareholders' equity:		
Common stock (375,764,429 and 424,524,178 shares outstanding at respective dates)	$ 2,261	$ 2,547
Cumulative translation adjustments — net	30	64
Unrealized gain in equity investments — net	60	33
Retained earnings	3,176	3,753
	5,527	6,397
Preferred securities of subsidiaries:		
Not subject to mandatory redemption	184	284
Subject to mandatory redemption	425	425
Long-term debt	8,871	7,475
Total capitalization	15,007	14,581
Other long-term liabilities	480	424
Current portion of long-term debt	868	592
Short-term debt	330	397
Accounts payable	441	438
Accrued taxes	577	530
Accrued interest	132	131
Dividends payable	95	109
Regulatory balancing accounts — net	—	182
Deferred unbilled revenue and other current liabilities	1,285	1,059
Total current liabilities	3,728	3,438
Accumulated deferred income taxes — net	4,085	4,283
Accumulated deferred investment tax credits	351	372
Customer advances and other deferred credits	1,441	754
Total deferred credits	5,877	5,409
Minority interest	9	707
Commitments and contingencies (Notes 2, 8, 9 and 10)		
Total capitalization and liabilities	$25,101	$24,559

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

Consolidated Statements of Cash Flows

In millions Year ended December 31,	1997	1996	1995
Cash flows from operating activities:			
Net income	$ 700	$ 717	$ 739
Adjustments for non-cash items:			
Depreciation and decommissioning	1,362	1,173	1,014
Amortization	88	96	73
Rate phase-in plan	47	79	111
Deferred income taxes and investment tax credits	115	91	(166)
Equity in income from partnerships and unconsolidated subsidiaries	(190)	(154)	(115)
Other long-term liabilities	56	80	33
Other — net	(131)	(98)	—
Changes in working capital:			
Receivables	(8)	68	(27)
Regulatory balancing accounts	(375)	(156)	282
Fuel inventory, materials and supplies	36	39	(19)
Prepayments and other current assets	10	13	(17)
Accrued interest and taxes	47	3	19
Accounts payable and other current liabilities	195	70	13
Distributions from partnerships and unconsolidated subsidiaries	182	176	178
Net cash provided by operating activities	2,134	2,197	2,118
Cash flows from financing activities:			
Long-term debt issued	1,646	1,365	1,496
Long-term debt repaid	(2,219)	(1,315)	(960)
Rate reduction notes issued	2,449	—	—
Preferred securities issued	—	414	63
Preferred securities redeemed	(100)	—	(75)
Common stock repurchased	(1,173)	(344)	(70)
Short-term debt financing — net	(68)	(312)	(46)
Dividends paid	(408)	(440)	(447)
Other — net	(14)	45	31
Net cash provided (used) by financing activities	113	(587)	(8)
Cash flows from investing activities:			
Additions to property and plant	(783)	(744)	(969)
Purchase of nonutility power stations	—	—	(1,015)
Funding of nuclear decommissioning trusts	(154)	(148)	(151)
Investments in partnerships and unconsolidated subsidiaries	(131)	(336)	(45)
Unrealized gain in equity investments — net	27	15	8
Other — net	(196)	(7)	35
Net cash used by investing activities	(1,237)	(1,220)	(2,137)
Net increase (decrease) in cash and equivalents	1,010	390	(27)
Cash and equivalents, beginning of year	897	507	534
Cash and equivalents, end of year	$ 1,907	$ 897	$ 507
Cash payments for interest and taxes:			
Interest — net of amounts capitalized	$ 579	$ 486	$ 463
Taxes	298	447	642
Non-cash investing and financing activities:			
Obligation to fund investments in partnerships and unconsolidated subsidiaries	237	237	466
Additions to property and plant funded by the minority owner of consolidated subsidiaries	—	33	77
Goodwill related to purchase of nonutility power stations	—	—	312

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

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting Principles

Southern California Edison Company's (SCE) accounting policies conform with generally accepted accounting principles (GAAP), including the accounting principles for rate-regulated enterprises which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). As a result of industry restructuring legislation enacted by the State of California and a related change in the application of accounting principles for rate-regulated enterprises adopted recently by the Financial Accounting Standards Board's Emerging Issues Task Force (EITF), during the third quarter of 1997 SCE began accounting for its investment in generation facilities in accordance with GAAP applicable to enterprises in general. Although this change did not result in any adjustment of the carrying value of such investment, the amount is shown separately on Edison International's Balance Sheet under the caption: Generation utility plant, at original cost, not subject to cost-based rate regulation. The competitive market for electric generation in California is scheduled to begin March 31, 1998.

Competition Transition Charge (CTC)

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

Consolidation Policy

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International's subsidiaries use the equity method to account for significant investments in partnerships and subsidiaries in which they own 50% or less. Intercompany transactions have been eliminated, except Edison Mission Energy's (EME) profits from energy sales to SCE, which are allowed in utility rates.

Earnings per Share (EPS)

Basic and diluted EPS are computed in accordance with a recently issued accounting standard. Basic EPS for Edison International equals previously reported primary EPS. EPS amounts were as follows:

In millions, except per-share amounts

	Income (Numerator)	Shares (Denominator)	Per-Share Amount
For the Year Ended December 31, 1997:			
Income	$ 743		
Less: dividends on subsidiary preferred securities	43		
Basic EPS			
Net income available to common shareholders	700	400	$ 1.75
Effect of dilutive securities:			
Employee stock options		4	
Diluted EPS	$ 700	404	$ 1.73
For the Year Ended December 31, 1996:			
Income	$ 764		
Less: dividends on subsidiary preferred securities	47		
Basic EPS			
Net income available to common shareholders	717	437	$ 1.64
Effect of dilutive securities:			
Employee stock options		2	
Diluted EPS	$ 717	439	$ 1.63
For the Year Ended December 31, 1995:			
Income	$ 786		
Less: dividends on subsidiary preferred securities	47		
Basic EPS			
Net income available to common shareholders	739	446	$ 1.66
Effect of dilutive securities:			
Employee stock options		2	
Diluted EPS	$ 739	448	$ 1.65

Estimates

Financial statements prepared in compliance with GAAP require management to make estimates and assumptions that affect the amounts reported in the financial statements and disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to electric utility restructuring, decommissioning and contingencies are further discussed in Notes 2, 9 and 10 to the Consolidated Financial Statements, respectively.

Fuel Inventory

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

Nature of Operations

Edison International's wholly owned subsidiaries include: SCE, a rate-regulated electric utility which produces and supplies electric energy for its 4.3 million customers in Central and Southern California; EME, a market leader in the development, ownership and operation of independent power facilities; Edison Capital, a leading provider of capital and financial services; and Edison Enterprises, the retail business arm of Edison International. EME and Edison Capital have domestic and foreign projects, primarily in Europe and Asia.

SCE currently operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing, as further discussed in Note 2 to the Consolidated Financial Statements. EME operates predominantly in one industry segment: independent, electric power generation. EME's domestic projects generally sell power to a limited number of electric utilities under long-term (15 to 30 years) contracts. EME's plants are located in different geographic areas, which mitigates the effects of regional markets, economic downturns or unusual weather conditions.

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

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

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

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

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

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

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

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 5.2% for 1997, 4.2% for 1996 and 3.6% for 1995.

Nonutility property is capitalized at cost, including interest incurred on borrowed funds that finance construction. Depreciation of nonutility properties is primarily computed on a straight-line basis over their estimated useful lives. Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 3.2% for 1997, 3.9% for 1996 and 3.8% for 1995.

During the third quarter of 1997, SCE discontinued accounting for its investment in generation facilities using accounting principles applicable to rate-regulated enterprises and began accounting for such investment using GAAP applicable to enterprises in general. The carrying value of such investment was unaffected by this change.

Reclassifications
Certain prior-year amounts were reclassified to conform to the December 31, 1997, financial statement presentation.

Regulatory Balancing Accounts
Prior to January 1, 1998, the differences between CPUC-authorized and actual base-rate revenue from kilowatt-hour sales and CPUC-authorized and actual energy costs were accumulated in balancing accounts until they were refunded to, or recovered from, utility customers through authorized rate adjustments (with interest). Beginning January 1, 1998, the difference between generation-related revenue and generation-related costs is being accumulated in a transition cost balancing account. These transition costs are being recovered from utility customers (with interest) through the CTC through 2001. Income tax effects on all balancing account changes are deferred.

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

Research, Development and Demonstration (RD&D)
SCE capitalizes RD&D costs that are expected to result in plant construction. If construction does not occur, these costs are charged to expense. RD&D expenses are recorded in a balancing account and, at the end of the rate-case cycle, any authorized but unspent RD&D funds are refunded to customers. RD&D expenses were $39 million in 1997, $21 million in 1996 and $28 million in 1995.

Revenue
Electric utility revenue includes amounts for services rendered but unbilled at the end of each year.

Note 2. Regulatory Matters

California Electric Utility Industry Restructuring

Restructuring Legislation — In September 1996, the State of California enacted legislation to provide a transition to a competitive market structure. The legislation substantially adopted the CPUC's December 1995 restructuring decision by addressing stranded-cost recovery for utilities and providing a certain cost-recovery time period for the transition costs associated with utility-owned generation-related assets. Transition costs related to power-purchase contracts would be recovered through the terms of their contracts while most of the remaining transition costs would be recovered through 2001. The legislation also included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which would allow SCE to reduce rates by at least 10% to these customers, beginning January 1, 1998. The financing would occur with securities issued by the California Infrastructure and Economic Development Bank, or an entity approved by the Bank. The legislation included a rate freeze for all other customers, including large commercial and industrial customers, as well as provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement during the 1998 – 2001 transition period. In addition, the legislation mandated the implementation of the CTC that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the legislation contained provisions for the recovery (through 2006) of reasonable employee-related transition costs, incurred and projected, for retraining, severance, early retirement, outplacement and related expenses.

Rate Reduction Notes — In May 1997, SCE filed an application with the CPUC requesting approval of the issuance of an aggregate amount of up to $3 billion of rate reduction notes in one or more series or classes and a 10% rate reduction for the period from January 1, 1998, through March 31, 2002. At the same time, SCE filed an application with the California Infrastructure and Economic Development Bank for approval to issue the notes. Residential and small commercial customers will repay the notes over the expected 10-year term through non-bypassable charges based on electricity consumption. In December 1997, after receiving approval from both the CPUC and the Infrastructure Bank, a limited liability company created by SCE issued approximately $2.5 billion of these notes. For further details, see the discussion under Long-Term Debt in Note 3 to the Consolidated Financial Statements.

CPUC Restructuring Decision — The CPUC's December 1995 decision on restructuring California's electric utility industry started the transition to a new market structure, which is expected to provide competition and customer choice and is scheduled to begin March 31, 1998. Key elements of the CPUC's restructuring decision included: creation of an independent power exchange (PX) and independent system operator (ISO); availability of direct customer access and customer choice; performance-based ratemaking (PBR) for those utility services not subject to competition; voluntary divestiture of at least 50% of utilities' gas-fueled generation, and implementation of the CTC.

Rate-setting — In December 1996, SCE filed a more comprehensive plan (elaborating on its July 1996 filing related to the conceptual aspects of separating costs as requested by CPUC and FERC directives) for the functional unbundling of its rates for electric service, beginning January 1, 1998. In response to CPUC and FERC orders, as well as the new restructuring legislation, this filing addressed the implementation-level detail for the functional unbundling of rates into separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The transmission component of this rate unbundling process was addressed at the FERC through a March 1997 filing. In December 1997, the FERC approved these rates, subject to refund, to be effective on the date the ISO begins operation. CPUC hearings on SCE's rate unbundling (also known as rate-setting) plan were concluded in April 1997. In August 1997, the CPUC issued a decision which adopted the methodology for determining CTC residually (see CTC discussion below) and adopted SCE's revenue requirement components for public benefit programs and nuclear decommissioning. The decision also adjusted SCE's proposed distribution revenue requirement by reallocating $76 million of the amount annually to other functions such as generation and transmission. Under the decision, SCE will be able to recover most of the reallocated amount through market revenue, other rate-making mechanisms after petitioning the CPUC to modify its prior decisions, or another review process later in its divestiture proceeding.

PX and ISO — In April 1996, SCE, Pacific Gas & Electric Company and San Diego Gas & Electric Company filed a proposal with the FERC regarding the creation of the PX and the ISO. In November 1996, the FERC conditionally accepted the proposal and directed the three utilities, the ISO, and the PX to file more specific information. The filing was made in March 1997, and included SCE's proposed transmission revenue requirement. On October 29, 1997, the FERC gave conditional, interim authorization for operation of the PX and ISO to begin on January 1, 1998. The FERC stated it would closely monitor the PX and ISO, require further studies and make modifications, where necessary. A comprehensive review will be performed by the FERC after three years of operation of the PX and ISO. On December 22, 1997, the PX and ISO governing boards announced a delay in the planned start-up of the PX and ISO due to insufficient testing of operational, settlement and billing systems. The PX and ISO are now expected to begin operation by March 31, 1998.

In July 1996, the three utilities jointly filed an application with the CPUC requesting approval to establish a restructuring trust which would obtain loans up to $250 million for the development of the ISO and PX through January 1, 1998. The loans are backed by utility guarantees; SCE's share was 45%, or $113 million. In August 1996, the CPUC issued an interim order establishing the restructuring trust and the funding level of $250 million, which has been used to build the hardware and software systems for the ISO and PX. The ISO and PX will repay the trust's loans and recover funds from future ISO and PX customers. In November 1997, the CPUC approved a petition jointly filed by the three utilities which requested an increase in the loan guarantees from $250 million to $300 million; SCE's share of this new total is $135 million. In December 1997, the CPUC approved a remaining item with respect to the petition which requested that the one-time restructuring implementation charge, to be paid to the PX by the utilities, be deemed a non-bypassable charge to be recovered from all retail customers. The amount of the PX charge is $85 million; SCE's share is 45%, or $38 million.

Direct Customer Access — In May 1997, the CPUC issued a decision describing how all California investor-owned-utility customers will be able to choose who will provide them with electric generation service beginning January 1, 1998. On December 30, 1997, the CPUC issued a decision delaying direct access until March 31, 1998, due to operational delays in the start-up of the PX and ISO. On this date, customers will be able to choose to remain utility customers with bundled electric service from SCE (which will purchase its power through the PX), or choose direct access, which means the customer can contract directly with either independent power producers or retail electric service providers such as power brokers, marketers and aggregators. Additionally, all investor-owned-utility customers must pay the CTC whether or not they choose to buy power through SCE. Electric utilities will continue to provide the core distribution service of delivering energy through its distribution system regardless of a customer's choice of electricity supplier. The CPUC will continue to regulate the prices and service obligations related to distribution services. If the new competitive market cannot accommodate the volume of direct access transactions, the CPUC could implement a contingency plan. However, the CPUC believes it is likely that interest in and migration to direct access will be gradual.

Revenue Cycle Services — A decision issued by the CPUC in May 1997, introduces customer choice to metering, billing and related services (referred to as revenue cycle services) that are now provided by California's investor-owned utilities. Under this revenue cycle services unbundling decision, beginning in January 1998, direct access customers may choose to have either SCE or their electric generation service provider render consolidated (energy and distribution) bills, or they may choose to have separate billings from each service provider. However, not all electric generation service providers will necessarily offer each billing option. In addition, beginning in January 1998, customers with maximum demand above 20 kW (primarily industrial and large commercial) can choose SCE or any other supplier to provide their metering service. All other customers will have this option beginning in January 1999. In determining whether any credit should be provided by the utility to firms providing customers with revenue cycle services, and the amount of any such credit, the CPUC has indicated that it is appropriate to net the cost incurred by the utility and the cost avoided by the utility as a result of such services being provided by the other firm rather than by the utility.

PBR — In 1993, SCE filed for a PBR mechanism to determine most of its revenue (excluding fuel). The filing was subsequently divided between transmission and distribution (T&D) and power generation.

In September 1996, the CPUC adopted a non-generation or T&D PBR mechanism for SCE which began on January 1, 1997. According to the CPUC, beginning in 1998 (coincident with the initiation of the competitive market), the transmission portion is to be separated from non-generation PBR and subject to ratemaking under the rules of the FERC. The distribution-only PBR will extend through December 2001. Key elements of the non-generation PBR include: T&D rates indexed for inflation based on the Consumer Price Index less a productivity factor; elimination of the kilowatt-hour sales adjustment; adjustments for cost changes that are not within SCE's control; a cost of capital trigger mechanism based on changes in a bond index; standards for service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from T&D operations.

With the CPUC's 1995 restructuring decision and the passage of restructuring legislation in 1996, the majority of power generation ratemaking (primarily fossil-fueled and nuclear) was assigned to other mechanisms. In April 1997, a CPUC interim order determined that the proposed structure of the fossil-fueled plants' must-run contracts were under the FERC's jurisdiction. On October 31, 1997, SCE filed must-run tariff schedules with the FERC covering its six ISO-designated must-run plants. In the meantime, SCE is pursuing the divestiture of these plants (see Divestiture discussion below) and might not ever itself provide service under these FERC tariff schedules.

In December 1997, the CPUC adopted a PBR-type rate-making mechanism for SCE's hydroelectric plants. The mechanism sets the hydroelectric revenue requirement in 1998 and establishes a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurs first. The mechanism provides that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement be credited against the costs to transition to a competitive market (see CTC discussion below).

Divestiture — In November 1996, SCE filed an application with the CPUC to voluntarily divest, by auction, all 12 of its oil- and gas-fueled generation plants. This application builds on SCE's March 1996 plan, which outlined how SCE proposed to divest 50% of these assets. Under the new proposal, SCE would continue to operate and maintain the divested power plants for at least two years following their sale, as mandated by the restructuring legislation enacted in September 1996. In addition, SCE would offer workforce transition programs to those employees who may be impacted by divestiture-related job reductions. SCE's proposal is contingent on the overall electric industry restructuring implementation process continuing on a satisfactory path. In September 1997, the CPUC approved SCE's proposal to auction the 12 plants.

On December 1, 1997, SCE filed a compliance filing with the CPUC stating that it had sold 10 plants. On December 16, 1997, the CPUC approved the sale of the 10 plants. On February 6, 1998, SCE filed a compliance filing with the CPUC regarding the sale of an 11th plant. CPUC approval of the sale is expected before March 31, 1998. The total sales price of the 11 plants is $1.1 billion, or 2.16 times their combined book value of $531 million. Net proceeds of the sales will be used to reduce stranded costs, which otherwise were expected to be collected through the CTC mechanism. The transfer of ownership of the 11 plants is expected to occur shortly before the start of the new competitive market, which the PX and ISO currently expect to occur on March 31, 1998. The sale and CPUC approval of the single remaining plant is expected to be completed in early 1998.

CTC — The CTC applies to all customers who were using or began using utility services on or after the CPUC's December 20, 1995, decision date. In August 1996, in compliance with the CPUC's restructuring decision, SCE filed its application to estimate its 1998 transition costs. In October 1996, SCE amended its transition cost filing to reflect the effects of the legislation enacted in September 1996. Under the rate freeze codified in the legislation, the CTC will be determined residually (i.e., after subtracting other cost components for the PX, T&D, nuclear decommissioning and public benefit programs). Nevertheless, the CPUC directed that the amended application provide estimates of SCE's potential transition costs from 1998 through 2030. SCE provided two estimates between approximately $13.1 billion (1998 net present value) assuming the fossil plants have a market value equal to their net book value, and $13.8 billion (1998 net present value) assuming the fossil plants have no market value. These estimates are based on incurred costs, forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. The potential transition costs are comprised of: $7.5 billion from SCE's qualifying facilities (QF) contracts, which are the direct result of prior legislative and regulatory mandates; and $5.6 billion to $6.3 billion from costs pertaining to certain generating plants (successful completion of the sale of SCE's gas-fired generating plants would reduce this estimate of transition costs for SCE-owned generation to less than $5 billion) and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre Units 2 and 3 and the Palo Verde units (as discussed in Note 1 to the Consolidated Financial Statements), and certain other costs. In February 1997, SCE filed an update to the CTC filing to reflect approval by the CPUC of settlements regarding ratemaking for SCE's share of Palo Verde and the buyout of a power purchase agreement, as well as other minor data updates. No substantive changes in the total CTC estimates were included. This issue has been separated into two phases; Phase 1 addresses the rate-making issues and Phase 2 the quantification issues.

A decision on Phase 1 was issued in June 1997, which, among other things, required the establishment of a transition cost balancing account and annual transition cost proceedings, set a market rate forecast for 1998 transition costs, and required that generation-related regulatory assets be amortized ratably over a 48-month period. Hearings on Phase 2 were held in May and June 1997 and a final decision was issued on November 19, 1997. The Phase 2 decision established the calculation methodologies and procedures for SCE to collect its transition costs from 1998 through the end of the rate freeze. The Phase 2 decision also reduced SCE's authorized rate of return on certain assets eligible for transition cost recovery (primarily fossil- and hydroelectric-generation related assets) beginning July 1997, five months earlier than anticipated. The decision, excluding the effects of other rate actions, had a negative impact on 1997 earnings of approximately 4¢ per share. SCE has filed an application for rehearing on the 1997 rate of return issue.

Accounting for Generation-Related Assets — If the CPUC's electric industry restructuring plan is implemented as outlined above, SCE would be allowed to recover its CTC through non-bypassable charges to its distribution customers (although its investment in certain generation assets would be subject to a lower authorized rate of return).

As previously reported, from November 1996 to July 1997, SCE and the other major California electric utilities were engaged in discussions with the Securities and Exchange Commission staff regarding the proper application of regulatory accounting standards in light of the electric industry restructuring legislation enacted by the State of California in September 1996 and the CPUC's electric industry restructuring plan. This issue was placed on the agenda of the EITF during April 1997 and a final consensus was reached at the July EITF meeting. During the third quarter of 1997, SCE implemented the EITF consensus and discontinued application of accounting principles for rate-regulated enterprises for its investment in generation facilities.

However, implementation of the EITF concensus did not require SCE to write off any of its generation-related assets, including regulatory assets of approximately $600 million at December 31, 1997. SCE has retained these assets on its balance sheet because the legislation and restructuring plan referred to above make probable their recovery through a CTC to distribution customers. These regulatory assets relate primarily to the recovery of accelerated income tax benefits previously flowed through to customers, purchased power contract termination payments, unamortized losses on reacquired debt, and the recovery of amounts deferred under the Palo Verde rate phase-in plan. The consensus reached by the EITF also permits the recording of new generation-related regulatory assets during the transition period that are probable of recovery through the CTC mechanism.

If during the transition period events were to occur that made the recovery of these generation-related regulatory assets no longer probable, SCE would be required to write off the remaining balance of such assets as a one-time, non-cash charge against earnings. If such a write-off were to be required, SCE believes that it should not affect the recovery of stranded costs provided for in the legislation and restructuring plan.

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

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

FERC Restructuring Decision

In April 1996, the FERC issued its decision on stranded-cost recovery and open access transmission, effective July 1996. The decision, reaffirmed by the FERC in its March and November 1997 orders, requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with increased access to transmission facilities for wholesale transactions and also establishes information requirements for the transmission utility. The decision also provides utilities with the opportunity to recover stranded costs associated with existing wholesale customers, retail-turned-wholesale customers and retail wheeling when the state regulatory body does not have authority to address retail stranded costs. Even though the CPUC is currently addressing stranded-cost recovery through the CTC proceedings, the FERC has also asserted primary jurisdiction over the recovery of stranded costs associated with retail-turned-wholesale customers, such as a new municipal electric system or a municipal annexation. However, the FERC did clarify that it does not intend to prevent or interfere with a state's authority and that it has discretion to defer to a state stranded-cost-calculation method. In January 1997, the FERC accepted the open access transmission tariff SCE filed in compliance with the April 1996 decision. The rates included in the tariff are being collected subject to refund. In May 1997, SCE filed a revised open access tariff to reflect the few revisions set forth in the March 1997 order. The open access transmission tariff will be terminated on the date the ISO begins operation.

Canadian Gas Contracts

In 1994, SCE filed its testimony in the non-QF phase of the 1994 Energy Cost Adjustment Clause proceeding. In 1995, the ORA filed its report on the reasonableness of SCE's gas supply costs for both the 1993 and 1994 record periods. The report recommended a disallowance of $13 million for excessive costs incurred from November 1993 through March 1994 associated with SCE's Canadian gas purchase and supply contracts. The report requested that the CPUC defer finding SCE's Canadian supply and transportation agreements reasonable for the duration of their terms and that the costs under these contracts be reviewed on a yearly basis. In 1996, the ORA issued its report for the 1995 record period recommending a $38 million disallowance for excessive costs incurred from April 1994 through March 1995. Both proposed disallowances were later consolidated into one proceeding. On December 3, 1997, the CPUC approved a settlement agreement between SCE and the ORA on this and any future issues, which will result in a $61 million (including interest) refund to SCE's customers. This refund is fully reflected in the financial statements and will be made in first quarter 1998.

Mojave Cogeneration Contract

In 1991, SCE filed its testimony in the QF phase of the 1991 Energy Cost Adjustment Clause proceeding. In 1993, the ORA filed its report on the reasonableness of SCE's QF contracts and alleged that SCE had imprudently renegotiated a QF contract with the Mojave Cogeneration Company. The report recommended a disallowance of $32 million (1993 net present value) over the contract's 20-year life. Subsequently, SCE and the ORA reached a settlement where SCE agreed to a one-time reduction to its energy cost adjustment clause balancing account of $14 million plus interest. In October 1996, the CPUC approved the settlement agreement, subject to SCE and the ORA accepting certain conditions concerning the way the $14 million payment would be reflected in rates. After reviewing the decision, SCE declined to accept the condition proposed by the CPUC and in November 1996 filed an application for rehearing. In February 1997, the CPUC denied SCE's application. Because SCE and the ORA were unable to finalize their settlement, hearings on the ORA's disallowance recommendations were held in June 1997. During the hearings, the ORA presented testimony to update its assessment of ratepayer harm, which it now estimates to be $45 million (1997 net present value) over the contract's life. In November 1997, a CPUC administrative law judge (ALJ) issued a proposed decision which would adopt the ORA's $45 million disallowance. In January 1998, the CPUC withdrew the ALJ's proposed decision pending oral arguments. Oral arguments were heard on February 4, 1998, at which time SCE requested an alternate proposed decision be issued. SCE expects this matter to be returned to the CPUC's agenda in the near future and a final decision to be issued during second quarter 1998. SCE cannot predict the final outcome of this matter but does not believe it will materially affect its results of operations.

Note 3. Financial Instruments

Cash Equivalents

Cash and equivalents include tax-exempt investments ($949 million at December 31, 1997, and $376 million at December 31, 1996), and time deposits and other investments ($958 million at December 31, 1997, and $521 million at December 31, 1996) with maturities of three months or less.

Derivative Financial Instruments

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

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

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

Projects in the United Kingdom sell their energy and capacity through a centralized electricity pool, which establishes a half-hourly clearing price for electrical energy. The pool price is extremely volatile, and can vary by a factor of 10 or more over the course of a few hours due to large differentials in demand according to the time of day. First Hydro mitigates a portion of the market risk of the pool by entering into electricity rate swap agreements, related to either the selling or purchase price of power. These contracts can be sold in two structures: one-way contracts, where a specified monthly amount is received in advance and difference payments are made when pool prices rise above the price specified in the contract, and two-way contracts, where First Hydro is paid when pool prices fall below the contract price instead of a specified monthly amount. These contracts attempt to stabilize production revenue or purchasing costs by removing an element of First Hydro's net exposure to pool price volatility.

Loy Yang B sells their electrical energy through a centralized electricity pool, which provides for a system of generator bidding, central dispatch and a settlement system based on a clearing market for each half-hour of every day. To mitigate the exposure to price volatility of the electricity traded in the pool, Loy Yang B has entered into a number of financial hedges. Between May 1997 and December 2000, approximately 53% to 64% of the plant output sold is hedged under vesting contracts, with the remainder of the plant capacity hedged under the state hedge described below. Vesting contracts set base strike prices at which the electricity will be traded, and the parties to the agreement make payments, calculated based on the difference between the price in the contract and the half-hourly pool clearing price for the element of power under the contract. These contracts can be sold as one-way or two-way contracts, which are similar to the electricity rate swap agreements described above. These contracts are accounted for as electricity rate swap agreements. The state hedge is a long-term contractual agreement based upon a fixed price commencing in May 1997 and terminating in October 2016.

Interest rate swaps, collars and caps are used to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. SCE's interest rate swap agreement requires the parties to pledge collateral according to bond rating and market interest rate changes. At December 31, 1997, SCE had pledged $19 million as collateral due to a decline in market interest rates. SCE is exposed to credit loss in the event of nonperformance by the counterparty to the agreement, but does not expect the counterparty to fail to meet its obligation.

Edison International is subject to concentrations of credit risk as the result of elements involved in EME's financial instruments and power-sales contracts. Credit risk relates to the risk of loss that EME would incur as a result of nonperformance by counterparties (major financial institutions and domestic and foreign utilities) under their contractual obligations. EME attempts to mitigate this risk by contracting with counterparties that have a strong capacity to meet their contractual obligations and by monitoring their credit quality. In addition, EME seeks to secure long-term power-sales contracts for its projects that are expected to result in adequate cash flow under a wide range of economic and operating circumstances. To accomplish this, EME attempts to structure its long-term contracts so that fluctuations in fuel costs will produce similar fluctuations in electric and/or steam revenue by entering into long-term fuel supply and transportation agreements. Accordingly, EME does not anticipate a material effect on its results of operations or financial condition as a result of counterparty nonperformance.

Edison International had the following interest rate hedges:

	December 31,			
	1997		*1996*	
In millions	*Notional Amount*	*Contract Expires*	*Notional Amount*	*Contract Expires*
Swaps:				
Fixed to variable	$ 441	1999 – 2008	$ 245	1999 – 2002
Variable to fixed	858	1998 – 2007	440	1997 – 2008
Collar:				
Variable to fixed	$ 77	1999	—	—
Cap:				
Variable to fixed	—	—	$ 30	1997

At December 31, 1997, SCE had gas call options valued at $34 million. These options mitigate SCE's exposure to increases in natural gas prices. Increases in natural gas prices tend to increase the price of electricity purchased from the PX. The options cover various periods from 1998 through 2001.

Fair Value of Financial Instruments

Fair values of financial instruments were:

	December 31,			
	1997		*1996*	
Instrument (in millions)	*Cost Basis*	*Fair Value*	*Cost Basis*	*Fair Value*
Financial assets:				
Decommissioning trusts	$ 1,371	$ 1,831	$ 1,217	$ 1,486
Electricity rate swaps	—	77	—	27
Equity investments	9	90	11	68
Gas call options	34	34	—	—
Financial liabilities:				
DOE decommissioning and decontamination fees	$ 50	$ 43	$ 54	$ 45
Interest rate hedges	—	92	—	34
Long-term debt	8,871	9,618	7,475	7,712
Preferred securities subject to mandatory redemption	425	451	425	445

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

Gross unrealized holding gains on financial assets were:

In millions December 31,	1997	1996
Decommissioning trusts:		
Municipal bonds	$ 131	$ 79
Stocks	190	138
U.S. government issues	91	39
Short-term and other	48	13
	460	269
Equity investments	81	57
Total	$ 541	$ 326

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

Investments

Net unrealized gains (losses) in equity investments are recorded as a separate component of shareholders' equity under the caption: Unrealized gain in equity investments – net. Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning.

All investments are classified as available-for-sale.

Long-Term Debt

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

Almost all SCE properties are subject to a trust indenture lien.

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

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

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

Long-term debt maturities and sinking-fund requirements for the next five years are: 1998—$848 million; 1999—$670 million; 2000—$719 million; 2001—$728 million; and 2002—$635 million.

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

The rate reduction notes have maturities ranging from one to 10 years, and bear interest at rates ranging from 5.98% to 6.42%. The rate reduction notes are secured solely by the transition property and certain other assets of the SPE, and there is no recourse to SCE or Edison International.

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

Long-term debt consisted of:

In millions December 31,	1997	1996
First and refunding mortgage bonds:		
1998—2026 (5.45% to 8.375%)	$ 1,825	$ 2,725
Rate reduction notes:		
1998—2007 (5.98% to 6.42%)	2,463	—
Pollution-control bonds:		
1999—2027 (5.4% to 7.2% and variable)	1,202	1,204
Funds held by trustees	(2)	(2)
Debentures and notes:		
1997—2026 (5% to 20% and variable)	4,028	3,891
Subordinated debentures:		
2044 (8.375%)	100	100
Commercial paper for nuclear fuel	92	112
Capital lease obligation	68	91
Current portion of capital lease obligation	(20)	(19)
Long-term debt due within one year	(848)	(573)
Unamortized debt discount – net	(37)	(54)
Total	$ 8,871	$ 7,475

On January 30, 1998, SCE redeemed $125 million of 8.375% first and refunding mortgage bonds, due 2017. Also, on January 30, 1998, a wholly owned financing subsidiary of SCE redeemed $200 million of 7.375% notes, due 2003.

Short-Term Debt

Short-term debt consisted of:

In millions *December 31,*	*1997*	*1996*
Commercial paper	$ 415	$ 470
Other short-term debt	8	167
Amount reclassified as long-term	(92)	(237)
Unamortized discount	(1)	(3)
Total	$ 330	$ 397
Weighted-average interest rate	6.0%	5.6%

At December 31, 1997, Edison International and its subsidiaries had $3.6 billion of borrowing capacity available. SCE had available lines of credit of $1.8 billion, with $1.3 billion for short-term debt and $500 million for the long-term refinancing of its variable-rate pollution-control bonds. The nonutility subsidiaries had lines of credit of $800 million available to finance general cash requirements. The parent company had available lines of credit totaling $1.0 billion. Edison International's unsecured revolving lines of credit are at negotiated or bank index rates with various expiration dates; the majority have five-year terms.

NOTE 4. EQUITY

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1997, SCE had the capacity to pay $1.4 billion in additional dividends and continue to maintain its authorized capital structure. These restrictions are not expected to affect Edison International's ability to meet its cash obligations.

Edison International's authorized common stock is 800 million shares with no par value.

Edison International purchased on the open market and retired the following amounts of common stock: in 1997—48,992,365 shares ($1.2 billion), in 1996—19,216,627 shares ($344 million) and in 1995—4,212,398 shares ($70 million).

Under Edison International's long-term incentive compensation plan, it issued 232,612 shares ($4.9 million) in 1997, 133,131 shares ($2.4 million) in 1996 and 20,900 shares ($0.4 million) in 1995.

SCE's authorized shares of preferred and preference stock are: $25 cumulative preferred—24 million; $100 cumulative preferred—12 million; and preference—50 million. All cumulative preferred stocks are redeemable. Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

EME is a general partner and also owns, indirectly, the limited partner's share of Mission Capital L.P., which was formed solely for the purpose of holding parent company debentures. Mission Capital L.P. has 6 million authorized shares of cumulative preferred securities with a liquidation preference that obligates EME.

Preferred stock redemption requirements for the next five years are: 1998 through 2001—zero and 2002—$105 million.

Edison International subsidiaries' cumulative preferred securities consisted of:

Dollars in millions, except per-share amounts	*December 31, 1997* *Shares Outstanding*	*Redemption Price*	*December 31,* *1997*	*1996*
Not subject to mandatory redemption:				
$25 par value preferred stock:				
4.08% Series	1,000,000	$ 25.50	$ 25	$ 25
4.24	1,200,000	25.80	30	30
4.32	1,653,429	28.75	41	41
4.78	1,296,769	25.80	33	33
5.80	2,200,000	25.25	55	55
7.36	—	—	—	100
Total			$ 184	$ 284
Subject to mandatory redemption:				
$25 par value preferred securities:				
8.50% Series	2,500,000	$ 25.00	$ 63	$ 63
9.875	3,500,000	25.00	87	87
$100 par value preferred stock:				
6.05% Series	750,000	100.00	75	75
6.45	1,000,000	100.00	100	100
7.23	1,000,000	100.00	100	100
Total			$ 425	$ 425

In 1997, 4 million shares of Series 7.36% preferred stock were redeemed. In 1995, 750,000 shares of Series 7.58% preferred stock were redeemed and 2.5 million of Series 8.50% preferred securities were issued. There were no preferred stock issuances or redemptions in 1996.

NOTE 5. INCOME TAXES

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

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

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

In millions December 31,	1997	1996
Deferred tax assets:		
Property-related	$ 227	$ 247
Unrealized gains or losses	273	201
Investment tax credits	192	206
Regulatory balancing accounts	180	298
Decommissioning-related	114	208
Other	691	366
Total	$ 1,677	$ 1,526
Deferred tax liabilities:		
Property-related	$ 4,010	$ 4,345
Leveraged leases	623	534
Capitalized software costs	127	122
Other	879	568
Total	$ 5,639	$ 5,569
Accumulated deferred income taxes–net	$ 3,962	$ 4,043
Classification of accumulated deferred income taxes:		
Included in deferred credits	$ 4,085	$ 4,283
Included in current assets	123	240

The current and deferred components of income tax expense were:

In millions Year ended December 31,	1997	1996	1995
Current:			
Federal	$ 244	$ 325	$ 507
State	55	108	150
Foreign	103	39	7
	402	472	664
Deferred:			
Accrued charges	(33)	(14)	1
Asset basis adjustment	18	(25)	12
Depreciation	(26)	71	72
Investment and energy tax credits–net	(22)	(37)	(26)
Leveraged leases	87	26	38
Loss carryforwards	121	(41)	(37)
Nonutility special charges	—	9	(21)
Pension reserves	(5)	45	(3)
Rate phase-in plan	(19)	(31)	(46)
Regulatory balancing accounts	141	34	(118)
State tax–privilege year	2	18	(9)
Other	(167)	(21)	(35)
	97	34	(172)
Total income tax expense	$ 499	$ 506	$ 492
Classification of income taxes:			
Included in operating income	$ 537	$ 563	$ 528
Included in other income	(38)	(57)	(36)

The composite federal and state statutory income tax rate was 40.551% for 1997 and 41.045% for 1996 and 1995.

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

Year ended December 31,	1997	1996	1995
Federal statutory rate	35.0%	35.0%	35.0%
Capitalized software	(0.8)	(0.8)	(0.8)
Depreciation and other	5.9	7.3	5.1
Housing credits	(4.3)	(3.6)	(2.7)
Investment and energy tax credits	(1.6)	(2.7)	(2.3)
State tax–net of federal deduction	6.3	6.2	5.6
Effective tax rate	40.5%	41.4%	39.9%

Note 6. Employee Compensation and Benefit Plans

Stock Option Plans

Under Edison International's Long-Term Incentive Compensation Plan, 8.2 million shares of common stock were reserved for potential issuance under various stock compensation programs to directors, officers and senior managers of Edison International and its affiliates. Under these programs, options on 4.4 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE. There were 3.2 million, 4.5 million, 5.4 million and 6.3 million shares reserved for future grant at December 31, 1997, 1996, 1995 and 1994, respectively.

Each option may be exercised to purchase one share of Edison International common stock, and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Edison International stock options include a dividend equivalent feature. Generally, for options issued before 1994, amounts equal to dividends accrue on the options at the same time and at the same rate as would be payable on the number of shares of Edison International common stock covered by the options. The amounts accumulate without interest. For Edison International stock options issued subsequent to 1993, dividend equivalents are subject to reduction unless certain shareholder return performance criteria are met.

Edison International stock options have a 10-year term with one-third of the total award vesting after each of the first three years of the award term. If an optionee retires, dies or is permanently and totally disabled during the three-year vesting period, the unvested options will vest and be exercisable to the extent of 1/36 of the grant for each full month of service during the vesting period. Unvested options of any person who has served in the past on the Edison International or SCE Management Committee will vest and be exercisable upon the member's retirement, death or permanent and total disability. Upon retirement, death or permanent and total disability, the vested options may continue to be exercised within their original terms by recipient or beneficiary. If an optionee is terminated other than by retirement, death or permanent and total disability, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

Edison International measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation program was $6 million, $9 million and $4 million for 1997, 1996 and 1995, respectively.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma earnings of $696 million, $714 million and $737 million for 1997, 1996 and 1995, respectively, and in pro forma basic earnings per share of $1.74, $1.63 and $1.65 for 1997, 1996 and 1995, respectively.

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

	1997	*1996*
Expected life	7.0 years	7.0 years
Risk-free interest rate	6.3%-6.8%	5.5%
Expected volatility	17%	17%

The recognition of dividend equivalents results in no dividends assumed for purposes of fair-value determination. The application of fair-value accounting to calculate the pro forma disclosures above is not an indication of future income statement effects. The pro forma disclosures do not reflect the effect of fair-value accounting on stock-based compensation awards granted prior to 1995.

A summary of the status of Edison International's stock options is as follows:

			Weighted-Average		
	Share Options	*Exercise Price*	*Exercise Price*	*Fair Value at Grant*	*Remaining Life*
Outstanding, Dec. 31, 1994	1,766,091	$ 16.00 – $ 24.44	$ 20.41		6.9 years
Granted	910,100	14.56 – 17.44	14.77	$ 6.92	
Expired	(9,930)	20.19 – 23.28	21.91		
Forfeited	(9,120)	14.56 – 21.94	19.74		
Exercised	(20,900)	17.38 – 17.75	17.64		
Outstanding, Dec. 31, 1995	2,636,241	$ 14.56 – $ 24.44	$ 18.69		7.0 years
Granted	1,091,850	15.81 – 18.31	17.57	$ 6.27	
Expired	(18,394)	14.56 – 23.28	20.08		
Forfeited	(21,810)	14.56 – 20.19	16.24		
Exercised	(133,131)	14.56 – 23.28	18.19		
Outstanding, Dec. 31, 1996	3,554,756	$ 14.56 – $ 24.44	$ 18.68		7.0 years
Granted	1,350,809	19.75 – 25.19	20.19	$ 7.62	
Expired	—	—	—		
Forfeited	(33,599)	14.56 – 19.75	17.76		
Exercised	(460,300)	14.56 – 23.28	19.06		
Outstanding, Dec. 31, 1997	4,411,666	$ 14.56 – $ 25.19	$ 18.76		7.0 years

The number of options exercisable and their weighted-average exercise prices at December 31, 1997, 1996 and 1995 were 3,218,189 at $18.48, 1,760,766 at $20.54 and 1,240,425 at $21.08, respectively.

Phantom Stock Options

Phantom stock option performance awards have been developed for two affiliate companies, EME and Edison Capital, as part of the Edison International long-term incentive compensation program for senior management. Each phantom stock option may be exercised to realize any appreciation in the deemed value of one hypothetical share of EME or Edison Capital stock over exercise prices. Exercise prices for EME and Edison Capital phantom stock are escalated on an annually compounded basis over the grant price by 12% and 7.75%, respectively. The deemed values of the phantom stock are recalculated annually as determined by a formula linked to the value of its portfolio of investments, less general and administrative costs. The options have a 10-year term with one-third of the total award vesting in each of the first three years of the award term.

Compensation expense recorded with respect to the phantom stock options was $79 million in 1997, $17 million in 1996 and $1 million in 1995.

Pension Plan

Edison International has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. Benefits are based on years of accredited service and average base pay. SCE funds the plan on a level-premium actuarial method. These funds are accumulated in an independent trust. Annual contributions meet minimum legal funding requirements and do not exceed the maximum amounts deductible for income taxes. Prior service costs from pension plan amendments are funded over 30 years. Plan assets are primarily common stocks, corporate and government bonds, and short-term investments. In 1996, Edison International recorded pension gains from a special voluntary early retirement program.

The plan's funded status was:

In millions December 31,	*1997*	*1996*
Actuarial present value of benefit obligation:		
Vested benefits	$ 1,588	$ 1,679
Nonvested benefits	130	73
Accumulated benefit obligation	1,718	1,752
Value of projected future compensation levels	398	267
Projected benefit obligation	$ 2,116	$ 2,019
Fair value of plan assets	$ 2,316	$ 2,171
Projected benefit obligation less than plan assets	$ (200)	$ (152)
Unrecognized net gain	305	294
Unrecognized prior service cost	(184)	(199)
Unrecognized net obligation (17-year amortization)	(40)	(45)
Pension liability (asset)	$ (119)	$ (102)
Discount rate	7.0%	7.75%
Rate of increase in future compensation	5.0%	5.0%
Expected long-term rate of return on assets	8.0%	8.0%

Edison International's utility operations recognize pension expense calculated under the actuarial method used for ratemaking.

The components of pension expense were:

In millions *Year ended December 31,*	*1997*	*1996*	*1995*
Service cost for benefits earned	$ 46	$ 51	$ 59
Interest cost on projected benefit obligation	140	180	157
Actual return on plan assets	(372)	(345)	(457)
Net amortization and deferral	224	146	270
Pension expense under accounting standards	38	32	29
Special termination benefits	—	1	3
Regulatory adjustment – deferred	17	22	23
Net pension expense recognized	55	55	55
Settlement gain	—	(121)	—
Total expense (gain)	$ 55	$ (66)	$ 55

Postretirement Benefits Other Than Pensions

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

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

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

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

In millions *December 31,*	*1997*	*1996*
Actuarial present value of benefit obligation:		
Retirees	$ 1,004	$ 933
Employees eligible to retire	45	35
Other employees	497	394
Accumulated benefit obligation	$ 1,546	$ 1,362
Fair value of plan assets	$ 815	$ 617
Plan assets less than accumulated benefit obligation	$ 731	$ 745
Unrecognized transition obligation	(405)	(432)
Unrecognized net gain (loss)	(245)	(236)
Recorded liability	$ 81	$ 77
Discount rate	7.0%	7.75%
Expected long-term rate of return on assets	8.0%	8.5%

The components of postretirement benefits other than pensions expense were:

In millions *Year ended December 31,*	*1997*	*1996*	*1995*
Service cost for benefits earned	$ 31	$ 33	$ 36
Interest cost on benefit obligation	100	91	78
Actual return on plan assets	(50)	(43)	(28)
Amortization of loss	5	6	1
Amortization of transition obligation	27	27	27
Net expense	113	114	114
Special termination expense	—	72	—
Total expense	$ 113	$ 186	$ 114

The assumed rate of future increases in the per-capita cost of health care benefits is 8.5% for 1998, gradually decreasing to 5.25% for 2004 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 1997, by $255 million and annual aggregate service and interest costs by $28 million.

Employee Savings Plan

Edison International has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $16 million in 1997, $25 million in 1996 and $20 million in 1995.

Note 7. Jointly Owned Utility Projects

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

The investment in each project, as included in the consolidated balance sheet as of December 31, 1997, was:

In millions	*Plant in Service*	*Accumulated Depreciation*	*Under Construction*	*Ownership Interest*
Transmission systems:				
Eldorado	$ 28	$ 9	$ 3	60%
Pacific Intertie	241	75	1	50
Generating stations:				
Four Corners (coal)				
Units 4 and 5	459	247	3	48
Mohave (coal)	307	146	5	56
Palo Verde (nuclear)	1,601	665	9	16
San Onofre (nuclear)	4,212	2,210	38	75
Total	$ 6,848	$ 3,352	$ 59	

Note 8. Leases

Leveraged Leases

Edison Capital is the lessor in several leveraged-lease agreements with terms of 13 to 38 years. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The total cost of these facilities was $3.1 billion and $1.8 billion at December 31, 1997, and 1996, respectively.

The equity investment in these facilities is 21% of the purchase price. The remainder is nonrecourse debt secured by first liens on the leased property. The lenders have accepted their security interests as their only remedy if the lessee defaults.

The net investment in leveraged leases consisted of:

In millions *December 31,*	*1997*	*1996*
Rentals receivable (net of principal and interest on nonrecourse debt)	$ 1,634	$ 830
Unearned income	(728)	(303)
Investment in leveraged leases	906	527
Estimated residual value	58	58
Deferred income taxes	(623)	(534)
Net investment in leveraged leases	$ 341	$ 51

Operating and Capital Leases

Edison International has operating leases, primarily for vehicles (with varying terms, provisions and expiration dates) and a capital lease ($68 million) for a nonutility power-production facility.

Estimated remaining commitments for noncancelable leases at December 31, 1997, were:

In millions	*Operating Leases*	*Capital Lease*
Year ended December 31,		
1998	$ 24	$ 27
1999	19	27
2000	15	27
2001	11	—
2002	8	—
Thereafter	26	1
Total future commitments	$ 103	82
Amount representing interest (9.65%)		(14)
Net commitments		$ 68

Note 9. Commitments

Nuclear Decommissioning

SCE plans to decommission its nuclear generating facilities at the end of each facility's operating license by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is estimated to cost $2.1 billion in current-year dollars, based on site-specific studies performed in 1993 for San Onofre and 1992 for Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. Decommissioning is scheduled to begin in 2013 at San Onofre and 2024 at Palo Verde. San Onofre Unit 1, which shut down in 1992, is expected to be secured until decommissioning begins at the other San Onofre units.

Decommissioning costs, which are accrued and recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense. Decommissioning expense was $154 million in 1997, $148 million in 1996 and $151 million in 1995. The accumulated provision for decommissioning was $1.1 billion at December 31, 1997, and $949 million at December 31, 1996. The estimated costs to decommission San Onofre Unit 1 ($280 million) are recorded as a liability.

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

Trust investments include:

In millions	*Maturity Dates*	*December 31, 1997*	*1996*
Municipal bonds	1998–2026	$ 459	$ 400
Stocks	—	392	549
U.S. government issues	1998–2027	357	212
Short-term and other	2002–2003	163	56
Trust fund balance (at cost)		$ 1,371	$ 1,217

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $54 million in 1997, $49 million in 1996 and $51 million in 1995. Proceeds from sales of securities (which are reinvested) were $595 million in 1997, and $1.0 billion in 1996 and in 1995. Approximately 89% of the trust fund contributions were tax-deductible.

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

Other Commitments

SCE and EME have fuel supply contracts which require payment only if the fuel is made available for purchase.

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. The QF contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is not expected to provide more than 5% of current or estimated future operating capacity. SCE's minimum commitment under both contracts is approximately $193 million through 2017.

Certain commitments for the years 1998 through 2002 are estimated below:

In millions	*1998*	*1999*	*2000*	*2001*	*2002*
Projected construction expenditures	$ 1,057	$ 807	$ 763	$ 721	$ 671
Fuel supply contracts	296	215	236	228	237
Purchased-power capacity payments	686	711	714	716	714
Unconditional purchase obligations	9	9	10	9	10

EME has firm commitments to make equity and other contributions to its projects of $295 million, primarily for the Paiton project in Indonesia, the ISAB project in Italy and the Doga project in Turkey. EME also has contingent obligations to make additional contributions of $181 million, primarily for equity support guarantees related to Paiton.

Note 10. Contingencies

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

Brooklyn Navy Yard Project

EME owns, through a wholly owned subsidiary, 50% of the Brooklyn Navy Yard project. On December 17, 1997, the Brooklyn Navy Yard project partnership completed a $407 million permanent, nonrecourse financing for the project.

In February 1997, the contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard Cogeneration Partners, L.P. (BNY) for damages in the amount of $137 million. In addition to defending this action, BNY has filed an action against the contractor in New York State Court asserting general monetary claims in excess of $13 million arising out of the turnkey agreement. EME agreed to indemnify the partnership and its partner from all claims and costs arising from or in connection with the contractor litigation, which indemnity has been assigned to the lenders. Edison International believes that the outcome of this litigation will not materially affect its results of operations or financial position.

Environmental Protection

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

Edison International records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts). While Edison International has numerous insurance policies that it believes may provide coverage for some of these liabilities, it does not recognize recoveries in its financial statements until they are realized.

In connection with the issuance of the San Onofre Units 2 and 3 operating permits, SCE reached an agreement with the California Coastal Commission in 1991 to restore certain marine mitigation sites. The restorations include two sites: designated wetlands and the construction of an artificial kelp reef off the California coast. After SCE requested certain modifications to the agreement, the Coastal Commission issued a final ruling in April 1997 to reduce the scope of remediations. SCE elected to pay for the costs of marine mitigation in lieu of placing the funds into a trust. Rate recovery of these costs is occurring through the San Onofre incentive pricing plan discussed in Note 1 to the Consolidated Financial Statements.

Edison International's recorded estimated minimum liability to remediate its 51 identified sites (50 at SCE and one at EME) is $178 million, which includes $75 million for the two sites discussed above. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $246 million. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental-cleanup costs at 41 of its sites, representing $91 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $153 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates. This amount includes $60 million of marine mitigation costs remaining to be recovered through the San Onofre incentive pricing plan.

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

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $10 million. Recorded costs for 1997 were $10 million.

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

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $8.9 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available

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

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued primarily by mutual insurance companies owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $28 million per year. Insurance premiums are charged to operating expense.

Note 11. Investments in Partnerships and Unconsolidated Subsidiaries

Edison International's nonutility subsidiaries have equity interests in energy generation projects and real estate investment partnerships.

Summarized financial information of these investments was:

In millions	*Year ended December 31,*	*1997*	*1996*	*1995*
Revenue		$ 1,946	$ 1,731	$ 1,400
Expenses		1,578	1,393	1,121
Net income		$ 368	$ 338	$ 279

In millions	*December 31,*	*1997*	*1996*
Current assets		$ 637	$ 673
Other assets		5,520	4,747
Total assets		$ 6,157	$ 5,420
Current liabilities		$ 949	$ 691
Other liabilities		3,592	3,110
Equity		1,616	1,619
Total liabilities and equity		$ 6,157	$ 5,420

Note 12. Business Segments

Edison International's business segments include electric utility operations (SCE) and three nonutility segments: unregulated power generation (EME); financial investments (Edison Capital); and retail services (Edison Enterprises). Other than EME, the nonutility segments are not individually significant and are combined for reporting purposes.

Edison International's business segment information was:

		Unregulated Power Generation			*Edison*
In millions	*Electric Utility*	*Domestic*	*Foreign*	*Other*	*International*
1997					
Operating revenue	$ 7,953	$ 192	$ 783	$ 307	$ 9,235
Operating income	1,642	78	316	(1)[1]	2,035[2]
Depreciation and decommissioning	1,240	15	88	19	1,362
Assets	18,059	926	4,059	2,057	25,101
Additions to property and plant	685	4	84	10	783
1996					
Operating revenue	$ 7,583	$ 170	$ 674	$ 118	$ 8,545
Operating income	1,711	75	292	(37)[1]	2,041[2]
Depreciation and decommissioning	1,064	15	75	19	1,173
Assets	17,737	949	4,204	1,669	24,559
Additions to property and plant	616	4	116	8	744
1995					
Operating revenue	$ 7,873	$ 177	$ 290	$ 65	$ 8,405
Operating income	1,709	73	131	(8)[1]	1,905[2]
Depreciation and decommissioning	954	10	36	14	1,014
Assets	18,155	842	3,532	1,417	23,946
Additions to property and plant	773	4	1,231[3]	3	2,011

Corporate items and eliminations are not material.

(1) Excludes reported tax benefits of $61 million in 1997, $80 million in 1996 and $44 million in 1995.

(2) Excludes income taxes of $537 million in 1997, $563 million in 1996 and $528 million in 1995.

(3) Includes $1,042 million from EME's acquisition of First Hydro.

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and Southern California Edison
A director since 1990

Winston H. Chen[2,3]
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Operating Officer,
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Director and Secretary-Treasurer,
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President, Joint Oceanographic
Institutions, Inc., and President,
Consortium for Oceanographic
Research and Education,
Washington, D.C.
A director since 1993

Edward Zapanta, M.D.[1,5]
Physician and Neurosurgeon,
Torrance, CA
A director since 1984

* 8/19/71 to 1/20/77
6/18/81 to 1/19/93
5/15/97 to present

1 Member of the Executive Committee
2 Member of the Finance Committee
3 Member of the Compensation and Executive Personnel Committee
4 Member of the Nominating Committee
5 Member of the Audit Committee
6 Retiring on April 16, 1998

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Edison International

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Chairman of the Board and CEO

Bryant C. Danner
Executive Vice President and General Counsel

Alan J. Fohrer
Executive Vice President and Chief Financial Officer

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

Robert G. Foster
Senior Vice President, Public Affairs

William J. Heller
Senior Vice President, Strategic Planning and New Business Development

Richard K. Bushey
Vice President and Controller

Lillian R. Gorman
Vice President, Human Resources

Thomas J. Higgins
Vice President, Corporate Communications

Mahvash Yazdi
Vice President and Chief Information Officer

Beverly P. Ryder
Corporate Secretary

Southern California Edison

John E. Bryson
Chairman of the Board and CEO

Stephen E. Frank
President and Chief Operating Officer

Bryant C. Danner
Executive Vice President and General Counsel

Alan J. Fohrer
Executive Vice President and Chief Financial Officer

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Executive Vice President, Generation Business Unit

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Richard M. Rosenblum
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Emiko Banfield
Vice President, Shared Services

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Vice President, Customer Solutions Business Unit

Richard K. Bushey
Vice President and Controller

Bruce C. Foster
Vice President, San Francisco Regulatory Affairs

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Lawrence D. Hamlin
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Vice President, Labor Relations

Dwight E. Nunn
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Frank J. Quevedo
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Senior Vice President

James V. Iaco, Jr.
Senior Vice President and Chief Financial Officer

Georgia R. Nelson
Senior Vice President

S. Linn Williams
Senior Vice President and General Counsel

Edison Capital — Mission Land Company

Thomas R. McDaniel
President and CEO, Edison Capital and Mission Land Company

Ashraf T. Dajani
Senior Vice President, Edison Capital

Richard E. Lucey
Senior Vice President and Chief Financial Officer, Edison Capital

Larry C. Mount
Vice President and General Counsel, Edison Capital

Charles W. Johnson
Executive Vice President, Mission Land Company

Edison Technology Solutions

Vikram S. Budhraja
President

Edison Enterprises

Stephen E. Pazian
President and CEO, Edison Enterprises

A. Robert Handell
President and Chief Operating Officer, Edison Source

Michael L. Merlo
President and Chief Operating Officer, Edison Select

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President, Edison Utility Alliances

Dennis A. Eastman
Senior Vice President and General Manager, Edison Utility Services

Clark W. Collins
Senior Vice President, Edison Enterprises

Kenneth Pickrahn
Vice President and Chief Financial Officer, Edison Enterprises

Selected Financial and Operating Data: 1993 - 1997

Dollars in millions, except per-share amounts	*1997*	*1996*	*1995*	*1994*	*1993*
Edison International and Subsidiaries					
Operating revenue	$ 9,235	$ 8,545	$ 8,405	$ 8,345	$ 7,839
Operating expenses	$ 7,737	$ 7,067	$ 7,028	$ 7,046	$ 6,611
Net income	$ 700	$ 717	$ 739	$ 681	$ 639
Weighted-average shares of common stock outstanding (in millions)	400	437	446	448	448
Per-share data:					
Basic earnings	$ 1.75	$ 1.64	$ 1.66	$ 1.52	$ 1.43
Diluted earnings	$ 1.73	$ 1.63	$ 1.65	$ 1.52	$ 1.42
Dividends paid	$ 1.00	$ 1.00	$ 1.00	$ 1.21	$ 1.41
Dividends declared	$ 1.00	$ 1.00	$ 1.00	$ 1.105	$ 1.415
Book value at year-end	$ 14.71	$ 15.07	$ 14.41	$ 13.72	$ 13.30
Market value at year-end	$ 27 3/16	$ 19 7/8	$ 17 5/8	$ 14 5/8	$ 20
Dividend payout ratio (paid)	57.1%	61.0%	60.2%	79.6%	98.6%
Rate of return on common equity	11.7%	11.1%	11.8%	11.3%	11.7%
Price/earnings ratio	15.5	12.1	10.6	9.6	14.0
Ratio of earnings to fixed charges	2.39	2.40	2.55	2.48	2.28
Assets	$25,101	$24,559	$23,946	$22,390	$21,831
Retained earnings	$ 3,176	$ 3,753	$ 3,700	$ 3,452	$ 3,266
Common shareholders' equity	$ 5,527	$ 6,397	$ 6,393	$ 6,144	$ 5,958
Preferred securities:					
Not subject to mandatory redemption	$ 184	$ 284	$ 284	$ 359	$ 359
Subject to mandatory redemption	$ 425	$ 425	$ 425	$ 362	$ 275
Long-term debt	$ 8,871	$ 7,475	$ 7,195	$ 6,347	$ 6,459
Southern California Edison Company					
Operating revenue	$ 7,953	$ 7,583	$ 7,873	$ 7,799	$ 7,397
Earnings	$ 576	$ 621	$ 643	$ 599	$ 637
Basic earnings per Edison International common share	$ 1.44	$ 1.42	$ 1.44	$ 1.34	$ 1.42
Rate of return on common equity	11.6%	12.1%	12.6%	12.0%	12.9%
Internal generation of funds	104%	153%	89%	76%	78%
Peak demand in megawatts (MW)	19,118	18,207	17,548	18,044	16,475
Generation capacity at peak (MW)	21,511	21,602	21,603	20,615	20,606
Kilowatt-hour sales (in millions)	77,234	75,572	74,296	77,986	73,308
Customers (in millions)	4.25	4.22	4.18	4.15	4.12
Full-time employees*	12,642	12,057	14,886	16,351	16,585
Edison Mission Energy					
Revenue	$ 975	$ 844	$ 467	$ 381	$ 291
Net income	$ 115	$ 92	$ 64	$ 55	$ 2
Assets	$ 4,985	$ 5,153	$ 4,374	$ 2,843	$ 2,286
Rate of return on common equity	12.2%	8.8%	9.5%	9.6%	0.3%
Ownership in operating projects (MW)	5,180	4,706	4,212	2,048	1,862
Full-time employees	1,140	940	902	690	673
Edison Capital					
Revenue	$ 138	$ 49	$ 49	$ 47	$ 39
Net income	$ 61	$ 41	$ 39	$ 33	$ 29
Assets	$ 1,783	$ 1,423	$ 1,063	$ 1,008	$ 972
Rate of return on common equity	23.2%	17.7%	18.5%	16.8%	14.5%
Full-time employees	85	70	42	33	20

**1993 and 1994 are based on twelve-month averages.*

Shareholder Information

Annual Meeting

The 1998 annual meeting of shareholders will be held on Thursday, April 16, 1998, at 10:00 a.m. at the Industry Hills Sheraton Resort and Conference Center, One Industry Hills Parkway, City of Industry, California.

Stock Listing and Trading Information

Edison International Common Stock

The New York and Pacific stock exchanges use the ticker symbol EIX. Daily papers list as EdisonInt.

Preferred Stock

Southern California Edison's preferred stocks are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange table under the symbol SoCalEd. The 6.05%, 6.45% and 7.23% series are not listed. The preferred securities of Mission Capital, an affiliate of Edison Mission Energy, are listed on the New York Stock Exchange under the ticker symbol MEPrA for the 9.875% series and MEPrB for the 8.50% series.

Transfer Agent and Registrar

Southern California Edison maintains shareholder records and is transfer agent and registrar for Edison International common stock and Southern California Edison preferred stocks. Shareholders may call Shareholder Services, 800.347.8625, between 8:00 a.m. and 4:00 p.m. (Pacific time) every business day regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 and W-9 forms;
- notices of and replacement of lost or destroyed stock certificates and dividend checks;
- requests to eliminate multiple annual report mailings;
- Edison International's Dividend Reinvestment Plan, including enrollments, withdrawals, terminations, sales, transfers and statements; and
- requests for access to online account information via Edison International's Internet Home Page, www.edisonx.com.

The address of Shareholder Services is:
P.O. Box 400, Rosemead, California 91770-0400. FAX: 626.302.4815

Dividend Reinvestment and Electronic Funds Transfer

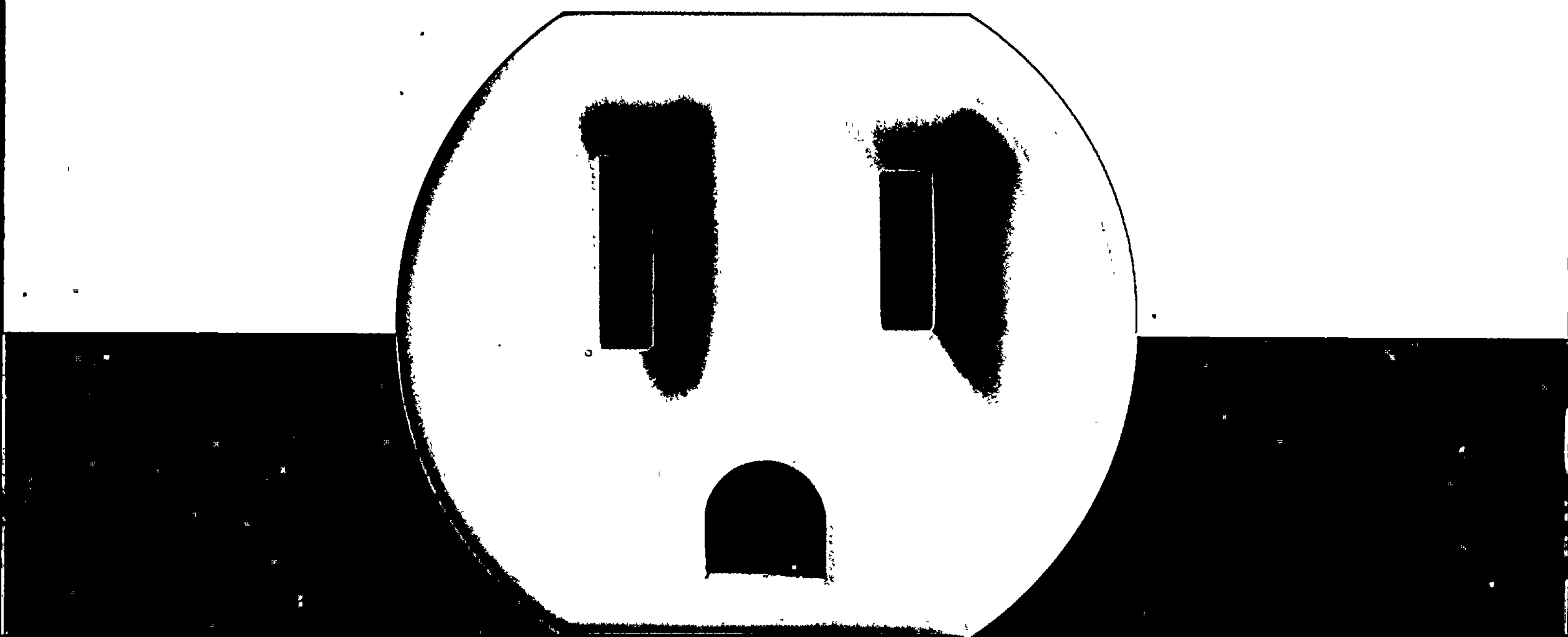
Shareholders can purchase additional common shares by reinvesting their quarterly dividends. A prospectus on Edison International's Dividend Reinvestment Plan is available from Shareholder Services.

Dividend checks can be electronically deposited directly to your financial institution. Enrollment forms are available upon request.

PUBLIC SERVICE COMPANY OF NEW MEXICO

PNM

1997 ANNUAL REPORT



CONTENTS

COMPANY PROFILE

PNM's primary business is providing electric and gas utility services to the people of New Mexico. We also sell power to utilities and other large wholesale customers, market natural gas outside the state of New Mexico, and offer a wide range of energy and water management services to municipalities, government agencies and other large commercial institutions.

INVESTOR HIGHLIGHTS

Dollars in thousands, except per share amounts

	1997	1996	PERCENTAGE CHANGE	5-YEAR ANNUAL GROWTH RATE
Financial Data				
Operating Revenues	$1,135,267	$883,386	28.5%	5.9%
Operating Expenses	$1,011,222	$757,367	33.5%	6.4%
Operating Income	$ 124,045	$126,019	(1.6%)	2.1%
Retained Earnings	$ 129,188	$ 77,185	67.4%	NM
Return on Average Common Equity	10.2%	9.8%	4.5%	NM
Common Share Data				
Earnings (Basic)	$ 1.92	$ 1.72	11.6%	NM
Earnings (Diluted)	$ 1.91	$ 1.71	11.7%	NM
Book Value	$ 19.26	$ 18.06	6.6%	5.1%
Closing Price	$ 23.69	$ 19.63	20.7%	13.9%

NM - *Not Meaningful*

MAKING

For PNM investors and for the people we serve, the change from regulated utility to competitive energy company brings new uncertainties, new risks – and new opportunities. In the following pages, we will tell you how the people of PNM are turning the revolutionary change in our industry to the benefit of our shareholders.

FELLOW SHAREHOLDERS:

PNM keeps getting better at what we do best: delivering reliable, cost-effective electric and gas service to the people of New Mexico. Providing superior value to customers continues to pay off for shareholders. In 1997 PNM stock provided a 25 percent total return on investment.

Thanks to continued strong growth in our local service territory, a substantial increase in our wholesale power sales and the rapid expansion of our new gas marketing business, PNM operating revenues were up $252 million last year, to more than $1.1 billion. Earnings per share increased 11.6 percent for the year.

This upward trend in revenues and earnings, together with your company's growing financial strength, enabled the Board of Directors to approve a 40 percent increase in the common stock dividend in 1997, from 48 to 68 cents a share for the year.

But tomorrow is not won by yesterday's success - and never has this been more true than in today's energy business. In California, retail electric competition is becoming a reality this year. Dozens of other states, including New Mexico, are working on their own plans to restructure the electric and gas utility industry. While these plans vary in detail, they all share one common goal: to offer customers expanded choice.

Utilities all across the country, each once comfortably secure in the uncontested possession of its local service territory, must now face the prospect of competing in the open market place. Some will succeed and some will fail.

We intend to have PNM ranked among the winners. We have a plan in place that will position your company for a competitive environment. We have a management team that has proven its ability to carry out that plan.

Although competition is bringing rapid and sometimes unpredictable change to our business, our commitment to maximizing your return on your investment in PNM remains constant. We are not simply waiting for the future. We are helping to create it.

Sincerely,

Benjamin F. Montoya

BENJAMIN F. MONTOYA
President & Chief Executive Officer

J. T. Ackerman

JOHN T. ACKERMAN
Chairman of the Board

IS THE

Choose One

IT USED TO BE A SIMPLE CHOICE: "ON" OR "OFF." • BUT TODAY, PNM CUSTOMERS HAVE NEW OPTIONS FOR THEIR NATURAL GAS. • SOON THEY'LL BE ABLE TO SELECT A POWER SUPPLIER AS WELL. • AS COMPETITION SPREADS, WE HAVE TO FIND NEW WAYS TO CONVINCE CUSTOMERS TO CHOOSE PNM.

CALL IT "RESTRUCTURING." CALL IT "RETAIL WHEELING," OR "OPEN ACCESS." BY WHATEVER NAME, CUSTOMER CHOICE IS COMING TO THE ELECTRIC UTILITY INDUSTRY ALL ACROSS THE COUNTRY.

At the beginning of 1997, customers told us they wanted greater control over their energy costs. PNM responded by leading the way to Gas Choice. We moved so fast that by the end of the year, PNM was one of the first natural gas utilities in the nation to offer all its customers the opportunity to shop for their supplier.

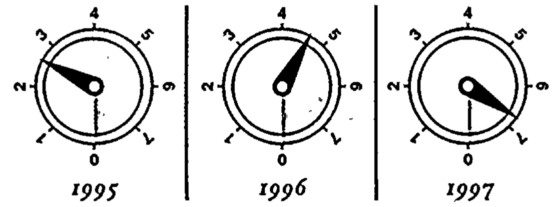
With the advent of Gas Choice, PNM continues to deliver the gas, read the meters and send out bills. But customers can now either continue to have PNM buy their gas for them or negotiate a separate deal with a gas marketer.

At the same time, we improved our own budget billing plan and offered an expanded array of options to help customers better manage their energy dollars. We extended the hours at our customer phone center so that customers could reach us on evenings and weekends. Because an energy efficient home saves customers money, PNM's Energy Place is offering customers a free Home Energy Analysis.

The PNM Advantage program offers the same expert assistance to business customers, identifying energy inefficiencies and suggesting money-saving solutions. The goal is to position PNM as a trusted energy adviser and ally, the customer's choice in a competitive market.

Competition came to the wholesale power business in 1992, when federal regulators opened the nationwide network of high-voltage transmission lines to all users. Last year the number of participants in this market – other utilities, independent power generators, and marketers – exploded to more than 300.

PNM adapted by expanding and reorganizing our wholesale power trading desk, staffing it with experts offering deals tailored to each customer's needs. As a result, these power sales were up 48.3 percent last year, on top of a 76.6 percent increase in 1996.



WHOLESALE POWER SALES
(GWh in thousands)
Sales to other utilities, municipalities, co-ops and marketers accounted for more than half of PNM's total electric sales in 1997.

Wholesale power sales accounted for $185.3 million of PNM revenues last year.

Because wholesale power has become a commodity product, where competitive advantage is measured in fractions of a cent, generating that electricity is also becoming a fiercely competitive business. We're finding new ways to make our own plants more efficient, without compromising our commitment to the environment. We have lowered costs at our San Juan plant and will lower them further with a $40 million investment in new emissions technology that will save us another $10 million a year.

Competition will take other forms in different parts of our business. Because building competing networks of electric and gas lines is economically wasteful, delivering energy to the customer's meter will remain a "natural monopoly," regulated much the way it is today. Providing that delivery service will offer steady profits and a reliable cash flow to efficient, well-managed companies.

The PNM electric and gas distribution systems are among the most reliable and cost-effective in the nation. And, for a relatively small utility like PNM, adding new customers offers substantial opportunities to further improve margins by capturing economies of scale.

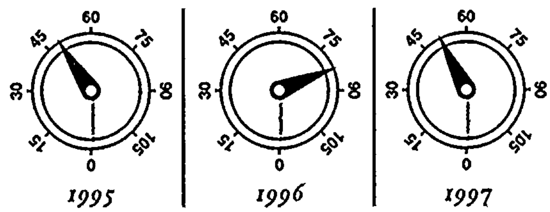
New Mexico remains one of the fastest-growing states in the nation. Through the 1990s, our vibrant local economy has fueled a growth rate for PNM of nearly twice the national average.

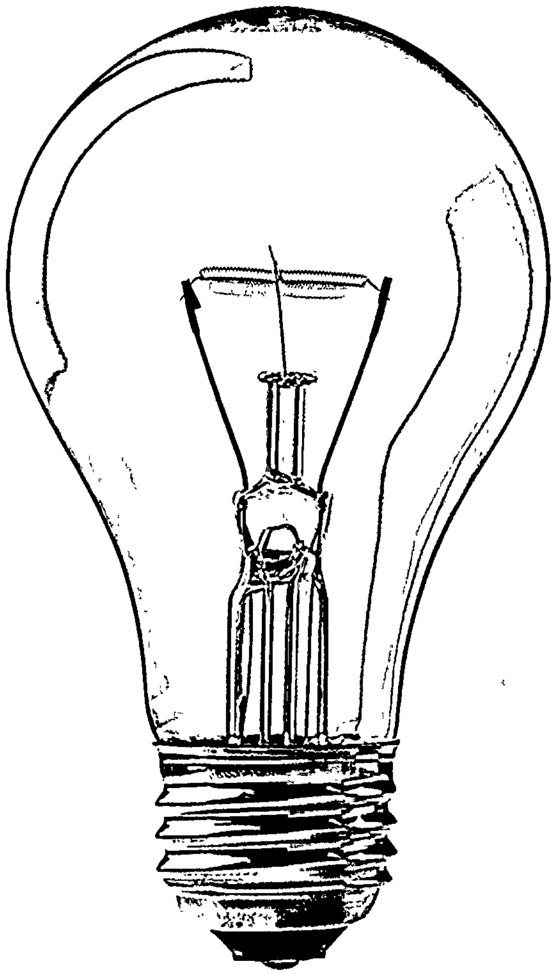
To serve more customers more efficiently, PNM is investing in the latest technology. PNM's new customer information computer system, our new interactive voice response system in the customer call center, and a new computerized trouble management system that dramatically speeds outage response time are all aimed at delivering superior service to customers at the lowest possible cost.

Improving the way we run our core business has other advantages beyond lowering costs and enhancing service to PNM retail customers. As deregulation of the industry proceeds, further "unbundling" of the basic utility package may make such basic functions as billing, meter reading, and phone center operations competitive offerings. When that day comes, PNM's superior performance in these areas may enable us to retain these services as profit centers.

AVERAGE CUSTOMER OUTAGE TIME
(minutes per year)

PNM's investment in equipment, systems and personnel resulted in power being restored to customers in record time in 1995 and 1997.





IN A COMPETITIVE ENVIRONMENT, YOU CAN'T AFFORD TO STAND STILL. • PNM IS CHARGING AHEAD. • WE ARE RETHINKING STRATEGY AND CHANGING INCENTIVES. • WE'RE ANSWERING THE TOUGH QUESTIONS THAT COME WITH A COMPETITIVE ENVIRONMENT WITH IDEAS THAT WILL SET US APART FROM THE COMPETITION.

IDEAS

LOW COSTS. AN EFFICIENT, PRODUCTIVE WORK FORCE. AN ORGANIZATION TOTALLY FOCUSED ON CREATING VALUE FOR SHAREHOLDERS BY MEETING THE NEEDS OF ITS CUSTOMERS. THOSE ARE THE ELEMENTS OF SUCCESS IN TODAY'S ENERGY BUSINESS.

A new company policy rewards employees with a casual dress day for every day PNM stock hits a new high. Sounds kind of silly at first, the kind of stunt Herb Kelleher used to revolutionize the airline business, or Sam Walton used in creating the nation's number-one mass retailer. But it works.

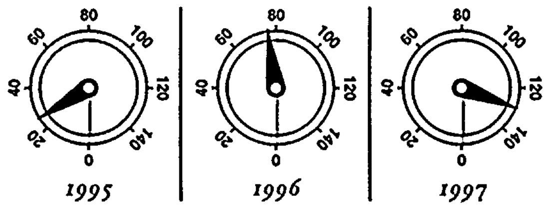
The "Stock's Up!" casual days are only one small example of the ways we are fostering a competitive mindset among PNM employees.

Our compensation plan pays workers for measurable results achieved, emphasizing return to shareholders and customer satisfaction. The new YES (You Energize Service) Award, instituted in mid-1997, rewards employees who go beyond their normal job duties to provide exceptional customer service.

We're looking at what has worked for companies in other industries, and to what's being tried by the "best practice" companies in our own industry. We're applying those lessons to PNM. The goal is not to simply streamline or fine-tune what we do now, but to re-examine every facet of our business so that we can do it better than anyone else.

In 1997, we assembled a team of experienced employees to tackle the company's largest re-engineering project to date. The team is studying how PNM spends $30 million a year to extend gas and electric service to new customers. The goal is to redesign this entire process to boost customer satisfaction, while assuring the most efficient use of the company's resources.

We're taking the same innovative approach to our financing needs. At the end of 1997, PNM took a major step toward eliminating reliance on the 50-year-old mortgage that served as the foundation for our financing arrangements in the past. In 1998, we will be one of the first utilities in the nation to use a



RETAINED EARNINGS
(dollars in millions)
Increased profitability boosted retained earnings to more than $129 million by the end of 1997.

new financial instrument that should make future borrowing easier and provide greatly increased financial flexibility.

We continue to repurchase, refinance or retire long-term debt, reducing interest expense and strengthening our balance sheet so that we will be able to respond quickly as opportunities arise in the future.

We're discovering some of those opportunities in the rapidly growing field of energy services, where today's heightened emphasis on conservation and environmental protection is fueling demand for the kinds of expert assistance PNM can provide.

PNM's strategy targets specialized segments of this new market where we can use our experience to build a profitable, competitive advantage.

One of these market niches is in serving the energy management needs of federal agencies and installations. Committed to reducing their energy consumption by nearly a third by 2005, these agencies are in the market for the innovative, cost-effective energy solutions available from PNM Energy Services. We are also putting our long years of experience to work with smaller municipalities and Indian reservations to help them upgrade, expand and manage their utility and water systems.

We are pursuing another new opportunity in selling natural gas to large industrial and commercial customers and to local gas utilities outside of New Mexico. We first entered this business in 1996 and grew it to more than $114 million in sales in 1997.

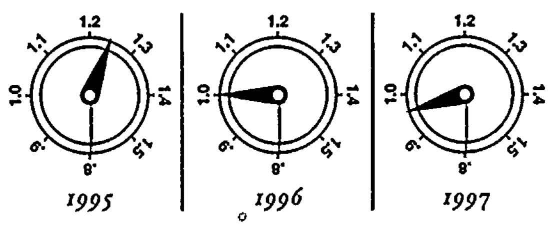
This year, we are starting up another new energy services business in the newly deregulated California market. This new business is installing and maintaining a new generation of high-tech electric meters for utilities and business customers.

These new ventures are a relatively small part of PNM's business today, and we do not expect them to contribute to earnings for several more years. Characteristic of a start-up business, in 1997 Energy Services reduced PNM earnings by about 22 cents a share.

But as these markets evolve and expand – and as PNM gains valuable experience in these new fields – we believe our investment in energy services will become an important source of revenues and profits for tomorrow's PNM.

LONG TERM DEBT OUTSTANDING
(dollars in billions)

PNM's aggressive debt reduction program has brought us closer to restoring the company's investment grade credit rating.



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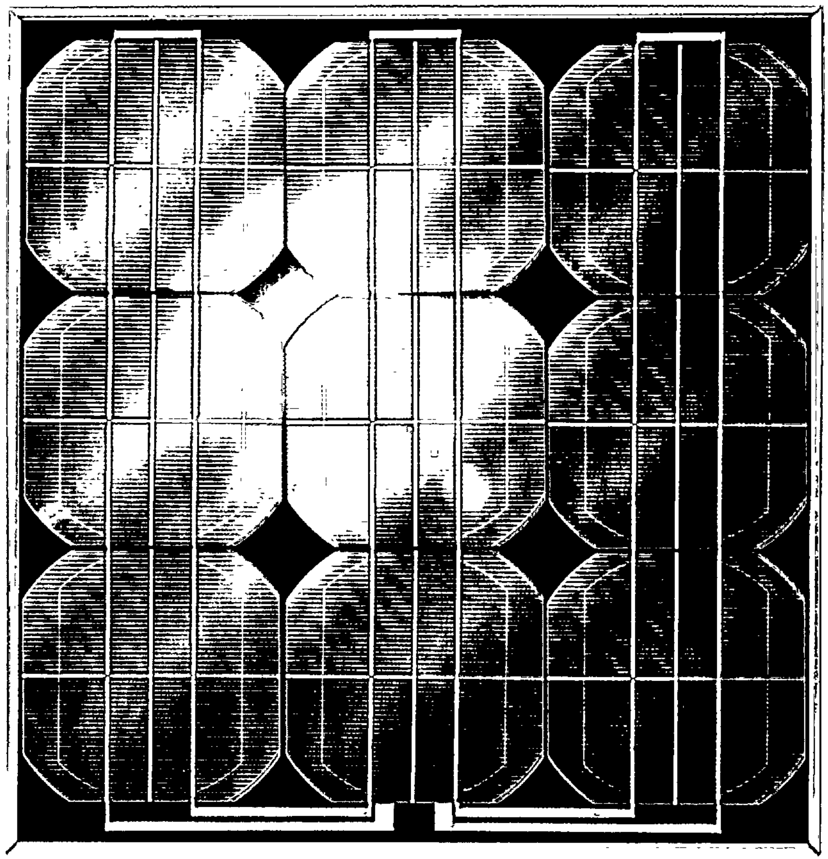


WILL COMPETITION MAKE A DIFFERENCE? • YES. • POWER GENERATED BY SOLAR PANELS LIKE THIS ONE WILL BE JUST ONE OF THE MANY NEW OPTIONS CONSUMERS WILL HAVE IN A COMPETITIVE MARKET. • AS ENERGY CHOICES MULTIPLY, WE ARE POSITIONING PNM TO GIVE CUSTOMERS WHAT THEY WANT.

We know that customers want an affordable, dependable supply of power. We also know that they care about the environment, and they want to deal with a company that shares that sense of stewardship.

As part of fulfilling that responsibility, we have established the new PNM Enchantment Energy Trust to fund projects that will assure New Mexico's continued leadership role in alternative energy research and development.

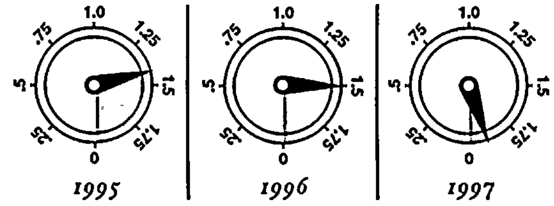
But even as we enter tomorrow's market place, we must continue to operate effectively in today's regulated environment, where substantial challenges remain. The New Mexico Public Utility Commission ordered PNM to present both an electric and a gas rate case in 1997. While we are seeking a $12.6 million increase in gas rates and advocating no change in electric rates, there is no certainty regarding the outcome of these cases.

Another uncertainty lies in New Mexico's move toward an elected Public Regulation Commission, which is scheduled to replace the existing Public Utility Commission in January 1999. The first elections to the new commission, together with state legislative and gubernatorial elections, will shape the ongoing debate over industry restructuring in New Mexico this year.

In 1997, PNM led the way in this debate, bringing together all interested parties in an attempt to reach a consensus over the changes in our industry. While those collaborative discussions did not produce a general agreement, the talks did help us all identify the important issues and find some common ground.

In 1998, PNM continues to advocate change that both offers benefits to all customers and serves the best interests of our shareholders.

In tomorrow's competitive market, consumers will be able to compare PNM side by side with other energy providers. In that new environment, the company with the latest technology, the company reinventing customer service, the company that is changing the way it does business, is the company that will thrive. PNM is committed to making competition work for our customers and our shareholders.



CUMULATIVE TOTAL RETURN
(dollars in thousands)

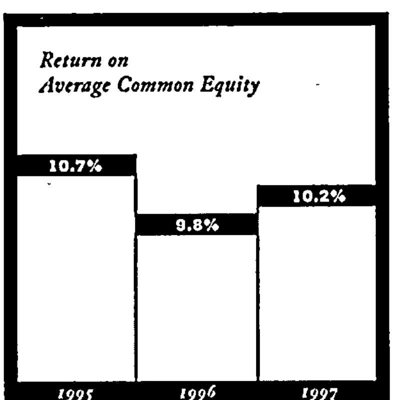
With dividends reinvested, $1,000 invested in PNM stock at the end of 1994 would have grown 91.6 percent, to $1,920, by the end of 1997.

SELECTED FINANCIAL DATA

	1997	1996	1995	1994	1993
	(In thousands except per share amounts and ratios)				
Total Operating Revenues	$1,135,267	$ 883,386	$ 808,465	$ 904,711	$ 873,878
Net Earnings (Loss)	$ 80,995	$ 72,580	$ 75,562	$ 80,318	$ (61,486)*
Earnings (Loss) per Common Share:					
Basic	$ 1.92	$ 1.72	$ 1.72	$ 1.77	$ (1.64)*
Diluted	$ 1.91	$ 1.71	$ 1.72	$ 1.77	$ (1.64)*
Total Assets	$2,313,732	$2,230,314	$2,035,669	$2,203,265	$2,212,189
Preferred Stock with Mandatory Redemption Requirements	–	–	–	$ 17,975	$ 24,386
Long-Term Debt, including Current Maturities	$ 714,345	$ 728,889	$ 728,989	$ 900,595	$ 976,525
Common Stock Data:					
Market price per common share at year end	$ 23.688	$ 19.625	$ 17.625	$ 13.00	$ 11.25
Book value per common share at year end	$ 19.26	$ 18.06	$ 16.82	$ 15.11	$ 13.29
Average number of common shares outstanding	41,774	41,774	41,774	41,774	41,774
Cash dividend declared per common share	$ 0.68	$ 0.48	–	–	–
Return on Average Common Equity	10.2%	9.8%	10.7%	12.4%	(10.7)%
Capitalization:					
Common stock equity	52.5%	50.4%	48.6%	39.2%	34.4 %
Preferred stock:					
Without mandatory redemption requirements	0.8	0.9	0.9	3.7	3.6
With mandatory redemption requirements	–	–	–	1.1	1.5
Long-term debt, including current maturities	46.7	48.7	50.5	56.0	60.5
	100%	100%	100%	100%	100 %

* Includes the write-down of the 22% beneficial interests in the PVNGS Units 1 and 2 leases purchased by the Company, the write-off of certain regulatory assets and other deferred costs and the write-off of certain PVNGS Units 1 and 2 common costs, aggregating $108.2 million, net of taxes ($2.59 per share).

The selected financial data should be read in conjunction with the consolidated financial statements, the notes to consolidated financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations.



PNM has provided consistent returns over the last three years, even as we have grown our business and restored the common stock dividend.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of the Company's financial condition and the significant factors affecting the results of operations. This discussion should be read in conjunction with the Company's consolidated financial statements.

OVERVIEW

Restructuring the Electric Utility Industry

Competition and restructuring of the electric utility industry continue to be key issues facing the Company. Efforts to advance and determine the eventual form of industry restructuring continued during 1997.

At the state level, the Company proposed in April 1997 that the New Mexico Public Utility Commission ("NMPUC") reconvene the proceedings involving the NMPUC's Notice of Inquiry into the restructuring of the electric industry, in an attempt to arrive at consensus legislation to be presented to the 1998 session of the New Mexico Legislature. In May 1997, the NMPUC issued an order accepting the Company's proposal for a collaborative effort, and the proposal for a series of meetings to be held among all interested parties. The parties held several meetings in which the Company actively participated. However, in September 1997, the collaborative process to draft legislation was declared at an impasse due to disagreement on issues regarding the divestiture of generation and energy service units from electric distribution and transmission systems, and the recoverability of stranded costs.

Although the parties could not reach agreement, the Company filed its own proposal for industry restructuring in September 1997 with both the NMPUC, and the Water, Utilities and Natural Resources Committee ("WUNR") of the New Mexico Legislature.

The Company's proposal called for an immediate rate reduction of $10 million per year for residential customers from the effective date of proposed legislation until open access without the need for a rate case. The proposal also called for full retail competition no later than January 1, 2001. Other parts of the Company's proposal included an offer to create a regulated distribution "wires and pipes" company dedicated only to the delivery of electricity and natural gas. Other services, usually associated with distribution, such as meter reading, billing and customer services would be provided through competitive markets. The Company offered to assume the risk of stranded cost recovery on all fossil fuel generation and for PVNGS Unit 3 which was previously excluded from New Mexico jurisdictional rates. However, the Company would recover all fixed costs associated with PVNGS Units 1 and 2 through a non-bypassable "wires charge" from 2001 to 2016. The proposal also called for certain credits to stranded costs which would effectively shorten the time period for recovery. The Company currently estimates that if the market clearing price for power, which represents the cost of generation at the plant, fell to 3.0 cents/KWh, it may incur an after-tax write-off of approximately $176 million related to its fossil fuel generation if the Company assumes this risk. The Company's proposal was supported by various parties to the collaborative process, including Enron Corporation, the New Mexico Retail Association, Southwestern Public Service Company ("SPS"), the United States Executive Agencies and the International Brotherhood of Electrical Workers. However, the Company's proposal was not adopted by the WUNR and not introduced during the1998 legislative session. The WUNR declined to recommend any restructuring legislation as a committee bill during the 1998 legislative session.

On January 22, 1998, the NMPUC submitted its own report to the New Mexico Legislature related to restructuring of the electric utility industry. The following key points were included in the report: (i) PVNGS and Plains Escalante Generating Station are the most debated issues in deregulation because of their potential stranded costs; (ii) stranded costs, if determined to be lawful, should be verified by the NMPUC or its successor, the Public Regulation Commission ("PRC"); (iii) market power issues may be addressed through functional separation or partial or complete divestiture of generation, transmission and distribution; (iv) unbundling is necessary to understand the disparities among various electricity providers; (v) despite an abundance of natural resources to fuel generation facilities, New Mexico customers pay more for electricity because of costs associated with generation plants; (vi) on average, New Mexico residential customers pay more for electricity than regional and national residential customers and (vii) system reliability must be maintained or enhanced, and customers must be educated and environmental protections should be promoted. In addition, sample legislation was attached to the report, giving either the NMPUC or the PRC authority to conclude matters relating to electric industry restructuring. The report was issued as a result of a NMPUC case and, with the issuance of the report, the case was closed. The NMPUC's draft legislation was not introduced during the 1998 legislative session. House

Memorial 27, the only measure dealing with restructuring, passed the House. Memorial 27 stated the intent of the legislature to address the issue of electric industry restructuring in the 1999 session and declared that the NMPUC does not have statutory authority to implement restructuring at this time. The Memorial 27 did not require concurrence by the Senate; however, an identical Senate Memorial was not acted upon by the full Senate prior to adjournment.

In a related matter, in 1996, the NMPUC ordered all utilities under its jurisdiction to file their estimates of stranded costs, absent any recovery method being adopted, based on the Texas Public Utility Commission Economic Cost Over Market ("ECOM") model. The Company, in its filing, presented two methodologies: (i) using the ECOM model, the Company's stranded cost estimates run from $657 million for a 1998 full retail access case to $119 million for a 2002 full retail access case and (ii) using a second methodology, based upon the difference between the Company's costs of existing generation and the costs of new combined cycle and combustion turbine units to serve the same load, the Company's costs above the level of new gas units, in 1997 dollars, were estimated at $748 million for a 1998 full retail access case to $327 million for a 2002 full retail access case. The Company advised the NMPUC that the results of the ECOM model are highly sensitive to various assumptions, primarily projections of future gas prices. This information was addressed in the NMPUC's report submitted to the New Mexico Legislature.

At the Federal level, legislation was introduced in the United States Congress in 1996 to allow retail competition by the year 2000. Since then, a number of bills have been drafted for potential introduction in Congress. It is anticipated that these bills will be heavily lobbied by utilities, industrials, power marketers, generators, environmental groups, consumer groups and state regulators.

The Federal Energy Regulatory Commission ("FERC") issued Order 888 in 1996, requiring utilities that own transmission facilities to file open access tariffs to make available transmission services to affiliates and non-affiliates at fair and nondiscriminatory rates. Order 888 also states that public utilities will be allowed to seek recovery of legitimate and verifiable stranded costs from departing customers as a result of wholesale competition. The FERC indicated that it will provide for the recovery of retail stranded costs only if state regulators lack the legal authority to address those costs at the time retail wheeling is required. The FERC also stated that it would permit stranded cost recovery under wholesale all-requirements contracts. However, upon reconsideration, FERC determined that it will serve as the primary forum for deciding stranded cost recovery cases if a non-jurisdictional municipal utility annexes territory currently served by a local retail utility. This move by FERC filled a jurisdictional gap that could have arisen since municipal utilities are not necessarily subject to state commission jurisdiction.

Although it is currently unable to predict the ultimate outcome of possible retail competition initiatives, the Company has been and will continue to be active at both the state and Federal levels in the public policy debates on the restructuring of the electric utility industry. The Company will continue to work with customers, regulators, legislators and other interested parties to find solutions that bring benefits from competition while recognizing past commitments.

Competitive Strategy

The Company's strategy for dealing with competition includes ongoing cost reductions, increased productivity, pursuit of growth opportunities, seeking to improve credit ratings to investment grade and strengthening of customer relations. To accomplish these objectives, the Company continues to maintain the focus on its core business and is aggressively pursuing its efforts to expand its energy and utility related business into carefully targeted markets for new businesses opportunities.

The restructuring of the utility industry, coupled with today's renewed emphasis on energy conservation and environmental protection, is fueling a growing demand for energy, water and wastewater management services. In pursuing new business opportunities, the Company is focusing on energy and utility related activities under its Energy Services Business Unit. These activities will provide energy marketing and energy management services, the marketing of natural gas outside of New Mexico, management services for water and wastewater systems and utility related management and operations services for Federal installations and other large commercial institutions. The Company is currently operating the City of Santa Fe's water system. The Energy Services Business Unit is also pursuing utility related business opportunities in Mexico.

In June 1995, the Company filed an application with the NMPUC for authorization for the creation of three wholly-owned non-utility subsidiaries as part of the Energy Services Business Unit. The Company sought approval to invest a maximum of $50 million in the three subsidiaries over time and to enter into reciprocal loan agreements for up to $30 million with these subsidiaries. In June 1997, the NMPUC hearing examiner issued a recommended decision for approval, with a number of conditions. The recommendation indicated that any capital infusion or financial assistance to its proposed subsidiaries beyond the requested $50 million and reciprocal loans exceeding more than $30 million with these subsidiaries will require prior approval from the NMPUC. The recommendation also directed that all investments made in the subsidiaries and their operations should not adversely affect the Company's ratepayers. The Company is currently awaiting the NMPUC's final order in this case.

The Company does not anticipate an earnings contribution from the Energy Services Business Unit over the next few years. However, the Company believes that successful operation of the Energy Services Business Unit activities will better position the Company in an increasingly competitive utility environment.

LIQUIDITY AND CAPITAL RESOURCES

Capital Requirements and Liquidity

Total capital requirements include construction expenditures as well as other major capital requirements, including retirement of long-term debt, long-term debt sinking funds and cash dividend requirements for both common and preferred stock. The main focus of the Company's construction program is upgrading generating systems, upgrading and expanding the electric and gas transmission and distribution systems and purchasing nuclear fuel. Total capital requirements and construction expenditures for 1997 were $173.9 million and $128.2 million, respectively. Projections for total capital requirements and construction expenditures for 1998 are $218.9 million and $141.3 million, respectively. Such projections for the years 1998 through 2002 are $940.3 million and $563.2 million, respectively. The projected capital requirements do not include the planned refinancing of $140 million of taxable first mortgage bonds or the planned refinancing of PVNGS Lease Obligation Bonds ("LOBs") discussed below. These estimates are under continuing review and subject to on-going adjustment. In conjunction with the upgrading of generating systems, the Company began a retrofit environmental project at San Juan Generating Station ("SJGS") which is scheduled to be completed in January 1999. The project will cost the Company approximately $40 million. The Company's anticipated savings in fuel and operating expense are estimated to be approximately $10 million per year over the life of the plant.

The Company's construction expenditures for 1997 were entirely funded through cash generated from operations. The Company currently anticipates that internal cash generation will be sufficient to meet capital requirements for the years 1998 through 2002. To cover the difference in the amounts and timing of cash generation and cash requirements, the Company intends to use short-term borrowings under its liquidity arrangements.

At the end of 1997, the Company had $130.0 million of available liquidity arrangements, consisting of $100.0 million from a secured revolving credit facility ("Facility"), $15.0 million from an accounts receivable securitization and $15.0 million in local lines of credit. The Facility will expire in June 1998 and the Company intends to replace the facility with a five-year $300 million senior unsecured revolving credit facility ("Revolver").

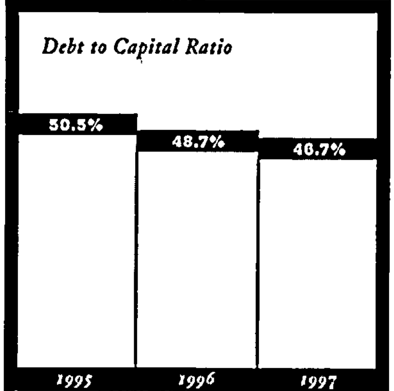
In November 1997, the Company requested NMPUC approval to enter into the Revolver. In addition, the Company intends to borrow $140 million from the Revolver to retire all of its outstanding taxable first mortgage bonds. The Company also requested authority to exchange the first mortgage bonds currently collateralizing the outstanding $575 million of tax-exempt pollution control revenue bonds with senior unsecured notes ("SUNs"). After completion of these transactions, the 1947 Indenture of Mortgage and Deed of Trust would be extinguished, resulting in more administrative, financial and strategic flexibility for the Company. The extinguishment of the mortgage requires the consent of one party which has not yet consented and may not consent. Due to concern about the consent, the Company also requested NMPUC authority to leave an amended mortgage in place. Among other modifications, the mortgage would be amended such that only $111 million of tax-exempt pollution control revenue bonds would have the benefit of the lien. The property under the lien would be reduced and no future bonds could be issued under the mortgage. The SUNs are planned to be issued under an indenture containing a restriction on liens (except in certain limited circumstances) and certain other covenants and restrictions. With the exception of the $111 million of tax-exempt pollution control revenue bonds secured by first mortgage bonds, the SUNs will be the senior debt of the Company. On February 16, 1998, the NMPUC issued an order approving these transactions. The Company is anticipating completion of these transactions in mid-March 1998.

As of December 31, 1997, the Company had approximately $18.2 million in cash and temporary investments.

Financing Capability

The Company's ability to finance its construction program at a reasonable cost and to provide for other capital needs is largely dependent upon its ability to earn a fair return on equity, results of operations, credit ratings, regulatory approvals and financial market conditions. Financing flexibility is enhanced by providing a high percentage of total capital requirements from internal sources and having the ability, if necessary, to issue long-term securities, and to obtain short-term credit. Standard & Poor's Corp. and Moody's Investors Services, Inc. currently maintain the Company's credit ratings at one level below investment grade. Duff & Phelps Credit Rating Co. currently maintains an investment grade rating for the Company's first mortgage bonds, but continues to rate all other securities of the Company below investment grade. The Company may face limited credit markets and higher financing costs as a result of its securities being rated below investment grade.

One impact of the Company's current ratings, together with covenants in the Company's PVNGS Units 1 and 2 lease agreements, is to limit the Company's ability, without consent of the owner participants and bondholders in the lease transactions: (i) to enter into any merger or consolidation, or (ii) except in connection with normal dividend policy, to convey, transfer, lease or dividend more than 5% of its assets in any single transaction or series of related transactions. The Facility imposes similar restrictions regardless of credit ratings.



PNM's lowered ratio of debt to total capital reflects the company's strengthened balance sheet and improved financial position.

The issuance of first mortgage bonds by the Company is subject to earnings and bondable property provisions of the Company's first mortgage bond indenture. The Company also has the capability under the mortgage indenture, without regard to the earnings test but subject to other conditions, to issue first mortgage bonds on the basis of certain previously retired bonds. At December 31, 1997, based on the earnings test, the Company could have issued approximately $463 million of additional first mortgage bonds, assuming an annual interest rate of 7.34 percent. The Company's restated articles of incorporation limit the amount of preferred stock which may be issued. Assuming a preferred stock dividend rate of 7.24 percent, the Company could have issued $525 million of preferred stock as of year-end.

Financing Activities

In February 1997, the Company refinanced $190 million of pollution control revenue bonds issued by the City of Farmington, all maturing in April 2022. The effect of the refinancing resulted in a decrease in interest charges of approximately $1.1 million in 1997. On December 1, 1997, the Company converted $137.3 million of variable rate pollution control revenue bonds to fixed rates. Of the total, $100 million of City of Farmington bonds were converted to a fixed rate of 5.80% and $37.3 million of Maricopa County, Arizona Pollution Control Corporation bonds were converted to a fixed rate of 5.75%. The City of Farmington bonds mature on April 1, 2022, and the Maricopa County, Arizona Pollution Control Corporation bonds mature on November 1, 2022.

In December 1997, the Company purchased $28.9 million of PVNGS LOBs, 10.15% Series. Although the LOBs are off-balance sheet debt, these outstanding bonds have been included in the calculation of the Company's debt to capitalization ratio as well as various financial coverage ratios by the major rating agencies. The purchase of the LOBs will not only improve these ratios, but will also increase earnings in the form of interest income.

The Company is currently preparing to request NMPUC approval to issue up to $443 million in fixed income securities to refinance the $208 million in LOBs remaining in the public markets and the $219 million in LOBs held by the Company as an investment. Under a stipulated agreement with the NMPUC, any savings generated from the refinancing will be split 40% to the Company's customers and 60% to shareholders. The Company hopes to complete the transaction during the second quarter of 1998.

Other than the financing activities discussed above, the Company currently has no requirements for long-term financing during the period of 1998 through 2002. However, during this period, the Company could enter into further long-term financings for the purpose of strengthening its balance sheet and reducing its cost of capital. The Company's continuing program of retiring or repurchasing long-term debt provided a net increase in earnings of approximately $9.7 million, before taxes, during 1997.

The Company continues to evaluate its investment and debt retirement options to optimize its financing strategy and earnings potential.

Dividends

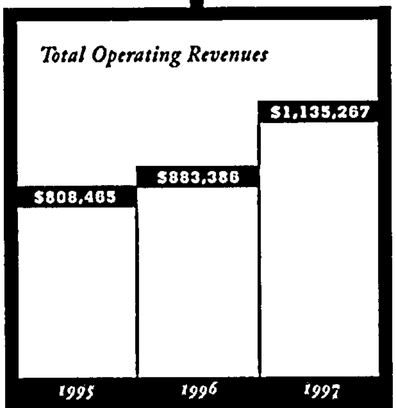
The Company resumed the payment of cash dividends on common stock in May 1996. The Company's board of directors ("Board") reviews the Company's dividend policy on a continuing basis. The declaration of common dividends is dependent upon a number of factors including earnings and financial condition of the Company and market conditions.

Capital Structure

The Company's capitalization, including current maturities of long-term debt, at December 31 is shown below:

	1997	1996	1995
Common Equity	52.5%	50.4%	48.6%
Preferred Stock	0.8	0.9	0.9
Long-term Debt	46.7	48.7	50.5
Total Capitalization*	100.0%	100.0%	100.0%

* Total capitalization does not include as debt the present value of the Company's lease obligations for PVNGS Units 1 and 2 and EIP.



RESULTS OF OPERATIONS

Basic earnings per share of common stock were $1.92, $1.72 and $1.72 for 1997, 1996 and 1995, respectively. Earnings in 1997 increased substantially above the 1996 level due to increased electric gross margin and interest income. The sales of the gas gathering and processing assets and the Company's water division in 1995 had a significant positive earnings effect in 1995 and impacted 1996 earnings by reducing operating margin, reducing operating expenses, reducing interest charges and increasing investment income.

Electric gross margin (operating revenues less fuel and purchased power expense) increased $20.1 million in 1997 from 1996 as a result of retail load growth and increased off-system sales margin as a result of continued improvement in wholesale power market conditions.

Electric gross margin increased $23.3 million in 1996 from 1995 as a result of retail load growth and warmer than normal weather and increased off-system sales margin as a result of improved wholesale power market conditions.

Gas gross margin (operating revenues less gas purchased for resale) increased $1.3 million in 1997 over 1996 resulting from the implementation of a higher fixed monthly customer charge (access fee) starting February 1997 pursuant to the NMPUC's final order in the gas rate case. This was offset by a reduced per therm rate per the NMPUC's final order and lower off-system sales margin.

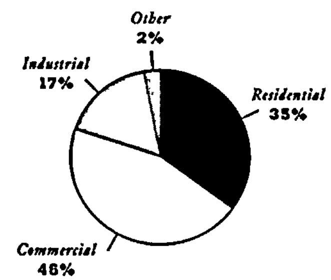
Gas gross margin in 1996 was unchanged from 1995. Higher off-system sales margin and higher retail sales margin as a result of cooler than normal weather in 1996 were offset by the absence of the gas gathering and processing margin in 1996 due to the sale of the gas gathering and processing assets in 1995.

The increase in the Energy Services Business Unit operating revenues and gas purchased for resale in 1997 was due to the Company's first full year of natural gas marketing operations outside of New Mexico. Gross margin decreased $4.6 million in 1997 from 1996 due mainly to a negative margin from the gas marketing operations as a result of unusual weather conditions on the West Coast and elsewhere around the country contributing to the volatility in natural gas prices during the fourth quarter of 1997. The Company does not anticipate an earnings contribution from the Energy Services Business Unit over the next few years.

Other operation and maintenance expenses ("O&M") increased $13.2 million in 1997 from 1996 due to the following: (i) higher operating expenses of $4.3 million related to the Energy Services Business Unit's operations; (ii) higher distribution expense of $4.2 million as a result of increased maintenance and service enhancement efforts; (iii) higher production expenses of $4.3 million resulting from the write-off of obsolete inventory and undistributed stores expense at PVNGS and a severance pay accrual at SJGS; (iv) higher customer related service expenses of $2.9 million resulting from the Company's customer enhancement program; (v) higher sales expense of $2.0 million and (vi) higher transmission expense of $1.1 million. Offsetting these increases were lower maintenance expense at Four Corners due to a scheduled maintenance outage in 1996, lower gas and oil production expense, and lower administrative and general ("A&G") labor and benefit expense.

Other O&M decreased $.3 million in 1996 from 1995 due to the following: (i) lower production expenses of $7.9 million as a result of reduced scheduled maintenance outages in 1996, decreased down time in 1996 for refueling outages and lower property taxes in 1996; (ii) a decrease of $6.3 million in gas production and products extraction expense resulting from the gas assets sale in June 1995; (iii) lower pension and benefit costs of $4.2 million as a result of an adjustment to the retirees' health care costs and (iv) a decrease in water division expense of $3.0 million resulting from the sale of the Company's water division in July 1995. These decreases were offset by higher A&G expense of $21.0 million due to increased labor, increased office supplies and expense and higher outside services expenses.

1997 Electric Revenues by Customer Class



Residential and commercial customers account for 81 percent of PNM's electric retail revenues.

Depreciation and amortization expenses increased $4.6 million in 1997 as a result of additional utility plant and an adjustment recorded in 1996 for the over amortization of certain intangible utility plant.

Depreciation and amortization expenses decreased $2.7 million in 1996 from 1995 as a result of the sale of the Company's water division and gas assets in 1995 and an adjustment recorded in 1996 for the over amortization of certain intangible utility plant.

Net other income and deductions increased $11.9 million from a year ago and decreased $18.8 million in 1996 from 1995. Significant 1997 items, net of taxes, included interest income of $14.3 million resulting from the investment in the PVNGS LOBs and settlement of litigation. Significant 1996 items, net of taxes, included the following: (i) a regulatory liability of $10.1 million; (ii) a $1.7 million write-down of certain assets related to the Company's natural gas vehicle program and (iii) an additional accrual of $1.0 million for environmental liabilities associated with the 1995 gas assets sale. Offsetting these decreases were a curtailment gain of $8.0 million related to the change of the Company's defined benefit pension plan and higher interest income of $7.6 million as a result of increased temporary investments in 1996 and the purchase of the PVNGS LOBs.

Significant 1995 items, net of taxes, included the following: (i) a gain of $12.8 million recognized from the gas assets sale; (ii) a gain of $6.4 million recognized from the sale of the Company's water division; (iii) a $2.6 million adjustment to the carrying costs related to gas take-or-pay settlement amounts; (iv) a $1.9 million insurance recovery and (v) a $1.4 million adjustment to reclamation reserves for certain mining operations. Offsetting these increases were: (i) additional regulatory reserves of $4.8 million and (ii) write-downs of $1.8 million for various non-utility properties.

Net interest charges increased $1.5 million in 1997 due to increased short-term borrowings for the purchase of the $200 million of PVNGS LOBs in October 1996 and interest accruals on the balance due customers related to the gain associated with the 1995 gas asset sale.

Net interest charges decreased $3.2 million in 1996 from 1995 as a result of the retirement of $132.7 million of PVNGS LOBs in March 1995. Offsets to the 1996 decrease were higher short-term interest charges resulting from short-term borrowings for the purchase of the PVNGS LOBs and an interest assessment from the Internal Revenue Service.

Preferred stock dividend requirements decreased $3.1 million in 1996 as a result of the retirement of $64 million of preferred stock in August 1995.

OTHER ISSUES FACING THE COMPANY

REGULATORY ISSUES

ELECTRIC RATE CASE

The NMPUC issued an order in May 1997, requiring the Company to file an electric rate case by September 1, 1997, if the collaborative process failed to reach consensus on an industry restructuring plan by August 1, 1997. In September 1997, the collaborative process was declared at an impasse. On October 21, 1997, the collaborative process was formally ended without a consensus (see *"Restructuring the Electric Utility Industry"* discussed above). As a result, on November 3, 1997, the Company filed its electric rate case. In the filing, the Company stated that although the Company could justify a $5.0 million rate increase, it would not seek to increase rates, stating that rate stability is important in preparing for industry restructuring.

In the Company's proposal for restructuring filed with the NMPUC and the WUNR, the Company had offered to reduce residential and small commercial customers rates by $10.0 million per year during the transition period, with another $5.0 million rate reduction upon the advent of full open access. The Company stated that these substantial rate reduction commitments in the context of industry restructuring may need to be modified if an additional rate reduction results from this rate case.

The NMPUC has scheduled public hearings for the rate case to begin on April 15, 1998. The Company anticipates a final order from the NMPUC during 1998. The Company is currently unable to predict the ultimate outcome of this case.

In conjunction with the Company's electric rate case filing, the Company requested the New Mexico Supreme Court ("Supreme Court") to issue an order disqualifying and removing the Chairman of the NMPUC from participating in this case. This request was based on his prior involvement in Company cases while he was with the New Mexico Attorney General ("AG's") office and in private practice. The Company stated that because of positions taken by the Chairman in past cases, the Company's due process rights for a fair hearing would be violated. The Supreme Court has established a briefing schedule and will hear oral arguments on April 13, 1998. Pending the decision, the Supreme Court has issued a stay prohibiting the Chairman from participating in the electric rate case.

THE 1995 GAS RATE CASE APPEAL

In 1995, the Company filed a request for a $13.3 million increase in its retail natural gas sales and transportation rates. On February 13, 1997, the NMPUC issued a final order in the gas rate case, ordering a rate decrease of approximately $6.9 million. In the order, the NMPUC disallowed, among other things, the recovery of certain regulatory assets. The Company strongly disagrees with the NMPUC's final order. The Company and the AG filed appeals with the Supreme Court. The Company is awaiting a decision by the Supreme Court, but is unable to predict the timing or the ultimate outcome. While the appeal is pending, the NMPUC's final order remains in effect.

THE 1997 GAS RATE CASE

By order issued in February 1997, as subsequently modified in April 1997, in a proceeding related to the cost of gas, the NMPUC ordered the Company to file a new gas rate case. On October 15, 1997, the Company completed the filing of the case, requesting a rate increase of $12.6 million. Also, the Company filed a motion for clarification and request for variance voluntarily disclosing that it had not performed and filed a study of fuel and unaccounted for gas usage in its system as required by the NMPUC in a 1990 order. The Company explained that it is currently performing such a study and only seeks a variance until the current study is completed. The NMPUC has scheduled public hearings for this case to begin on March 23, 1998.

The NMPUC staff and intervenors in the rate case filed their testimony on February 16, 1998. The NMPUC staff recommended an increase of $2.5 million to current rates while the AG recommended a decrease of $4.9 million. Both recommendations are significantly lower than the Company's request for a $12.6 million rate increase. Other parties to the case recommended certain adjustments to the Company's proposed rate increase. The Company is currently reviewing all testimony and will file its rebuttal testimony on March 13, 1998. The Company anticipates a final order from the NMPUC during 1998. The Company is currently unable to predict the ultimate outcome of this case.

INVESTIGATION RELATING TO AMOUNT OF FUEL AND UNACCOUNTED FOR GAS COSTS PASSED THROUGH THE PUBLIC SERVICE COMPANY OF NEW MEXICO GAS SERVICES' PURCHASED GAS ADJUSTMENT CLAUSE ("PNMGS' PGAC")

In connection with the motion for clarification filed in the 1997 gas rate case concerning the study of fuel and unaccounted for gas, the NMPUC staff requested that the NMPUC docket an investigation into the amount of fuel and unaccounted for gas costs that have passed through the Company's PGAC. The NMPUC staff is concerned that a 1995 reduction in the rate for fuel and unaccounted for gas collected from transportation customers may have unfairly shifted costs to sales customers. The NMPUC staff's motion seeks an investigation into the amount of fuel and unaccounted for gas associated with the Company's transmission and distribution systems, the actual amount of fuel and unaccounted for gas that should have been allocated to sales customers beginning in July 1995 and the amount, if any, of improper cost shifting that may have occurred as the result of the 1995 reduction. The Company has responded that it is not opposed to the requested investigation and believes that the results of the investigation will demonstrate that there has been no significant cost shifting resulting from the reduction in the factor charged to transportation customers.

CITY OF ALBUQUERQUE ("COA") RETAIL PILOT LOAD AGGREGATION PROGRAM

In September 1997, the COA filed a petition with the NMPUC to institute a Retail Pilot Load Aggregation Program that would run from January 1, 1998 through December 31, 1998. The petition requests that the NMPUC provide: (i) an expedited registration/certification process; (ii) an NMPUC order compelling transmission (by the Company) on behalf of COA; (iii) derivation of retail rates exclusive of the Company's production costs; (iv) arbitration assistance to facilitate a "true-up" or reconciliation of any over or under recovered costs and (v) arbitration assistance to accommodate metering, billing, and collection processes.

In January 1998, hearings on this case were conducted. At the hearings, the Company stated its position as follows: (i) the Company believes that only the New Mexico Legislature has the authority to order retail competition or a pilot on retail access; (ii) several pilots have already been conducted in other states and the key implementation issues to be addressed in a transition to a competitive environment have already been identified and (iii) if state legislation were passed regarding electric industry restructuring, a pilot as a component of that legislation could be useful to test the enabling systems and infrastructure necessary to implement that legislation on a small scale prior to implementation of full scale open access. The Company also identified numerous problems with the COA proposed pilot program, as it is not structured to provide benefits to anyone other than COA.

The NMPUC staff presented an alternative proposal to the COA pilot proposal, which was for a larger pilot that included a broader mix of customer classes. At the hearing, the COA was receptive to the proposal and suggested that it be run coincidentally with COA's pilot. The NMPUC staff also proposed that the NMPUC order a separate proceeding to identify what stranded costs, transition costs and administrative costs would be incurred by the Company in connection with a pilot and the proper methodology for quantifying any appropriate recovery.

The Company believes it is entitled to recover all of its costs, less avoided production costs, if a pilot is pursued, but has moved to dismiss this case for lack of jurisdiction by the NMPUC and lack of standing to file the case by the COA. The NMPUC has not ruled on the motion. The NMPUC has not issued an order on this case. Once an order is issued, the Company will review the findings and will evaluate its options at that time.

SAN DIEGO GAS AND ELECTRIC COMPANY'S ("SDG&E") COMPLAINTS

The Company has a contract with SDG&E which requires SDG&E to purchase 100 MW from the Company through April 2001. In 1993, SDG&E filed a complaint with the FERC against the Company, alleging that certain charges under the 1985 power purchase agreement were unjust, unreasonable and unduly discriminatory. In 1996, SDG&E filed a second complaint with the FERC against the Company, again alleging that charges under the agreement were unjust, unreasonable and unduly discriminatory. SDG&E has requested the FERC, in both complaints, to investigate charges under the agreement.

On August 22, 1997, SDG&E filed a third complaint with the FERC against the Company, again alleging that charges under the agreement were unjust, unreasonable and unduly discriminatory. SDG&E is again requesting that the FERC investigate charges under the agreement. The Company responded to the third complaint on September 29, 1997. The relief sought by SDG&E under the third complaint is similar to that requested under the first and second complaints. The refund period requested in the third complaint, if granted, would extend for a fifteen month period beginning October 21, 1997. The FERC has not issued a ruling on any of the three complaints and has not indicated when or if any of these complaints will be considered. The relief, as a result of all three complaints, if granted, would reduce annual demand charges paid by SDG&E by approximately $11 million per year from the date of the ruling through April 2001, and could result in a refund of approximately $27 to $31 million as of December 31, 1997. The Company believes that all three of the complaints are without merit and intends to vigorously resist all three complaints.

NATURAL GAS MARKETING ACTIVITIES

The Company is currently marketing natural gas in wholesale markets outside of New Mexico in its Energy Services Business Unit. As of December 31, 1997, the Company served over 120 end-user facilities in California and has many industrial and utility customer commitments throughout the Pacific Northwest, Rocky Mountain and Mid-continent regions. The gas contract portfolio currently extends through June 1999.

In 1997, the Company relied on physical commodity contracts to mitigate its price risk exposure. Reliance on physical commodity contracts subjects the Company to market, liquidity, performance and other risks that can have negative impacts on margins. In 1997, the Company experienced margin losses of $4.4 million on sales of approximately $115 million related to its gas marketing activities. Although the Company attempts to manage the risks associated with its fixed price physical contracts in terms of contract volumes and prices, net open positions exist. To the extent these net open positions exist, the Company is exposed to the risk of fluctuating market prices which may result in future losses to the Company.

During 1997, the Company did not use derivative financial instruments to manage its price risk exposure in the marketing of natural gas. However, the Company anticipates using derivative financial instruments beginning in 1998.

The Company measures the risk in the Company's commodity portfolio in accordance with the "value-at-risk" methodology. This methodology uses forward price curves in the energy markets to estimate the size and probability of future gains and losses. The Company also monitors compliance with policies approved by the Board relating to its trading activities.

THE IMPACT OF THE YEAR 2000 ISSUE

The Company is continuing to assess the impact of the Year 2000 issue on its reporting systems, equipment and operations. The Year 2000 issue is the result of computer programs being written using two digits rather than four to define the applicable year. As a result, the computer systems could recognize the year 2000 as the year 1900. This could result in a system failure or miscalculations causing disruptions of operations. Equipment that contains embedded chips may also be affected by the Year 2000 issue. Equipment affected may range from hand held calculators, elevators, routers, transformers and generators.

The Company plans to use both internal and external resources to have its critical systems Year 2000 compliant by mid-1999. The Company is currently replacing two major software systems which are projected to be completed during 1998 and will be Year 2000 compliant. However, the Company anticipates that the conversion of certain non-critical systems may not be completed until late 1999. In addition, certain portions of the project could be delayed if new hardware or software upgrades are not available on time. As part of the Year 2000 project, the Company also plans to inquire of other companies with which it transacts business regarding their Year 2000 compliance issues in order to identify any potential adverse impact to the Company.

The Company is in the process of assessing the cost to resolve the impact of the Year 2000 issue on its operations, and anticipates to complete its assessment by the end of 1998. The Company believes that if modifications, conversions and replacements are not completed timely, the Year 2000 issue could have a material adverse impact on the Company's operations.

ENVIRONMENTAL ISSUES

The Company is committed to complying with all applicable environmental regulations. Environmental issues have presented and will continue to present a challenge to the Company. The Company has evaluated the potential impacts of the following environmental issues and believes, after consideration of established reserves, that the ultimate outcome of these environmental issues will not have a material adverse effect on the Company's financial condition or results of operations.

ELECTRIC OPERATIONS

Santa Fe Generating Station ("Santa Fe Station")

The Company and the New Mexico Environment Department ("NMED") have conducted investigations of the groundwater contamination detected beneath the former Santa Fe Station site to determine the source of the contamination. The Company has been and is continuing to cooperate with the NMED regarding site investigations and remedial planning pursuant to a Settlement Agreement between the Company and the NMED. In June 1996, the Company received a letter from the NMED, indicating that the NMED believes the Company is the source of gasoline contamination in a municipal well supplying the City of Santa Fe and groundwater underlying the Santa Fe Station. Further, the NMED letter stated that the Company was required to proceed with interim remediation of the contamination pursuant to the New Mexico Water Quality Control Commission ("NMWQCC") regulations. In July 1996, the Company filed an appeal with the NMWQCC protesting the determination and directives contained in the NMED's June 1996 letter. Subsequently, negotiation meetings were conducted between the Company and the NMED for a resolution of the groundwater contamination issue.

On October 3, 1996, the Company and the NMED signed an Amendment to the Settlement Agreement concerning the groundwater contamination underlying the site. As part of the Amendment, the Company agreed to spend approximately $1.2 million ("Settlement Amount") for certain costs related to sampling, monitoring, and development and implementation of a remediation plan.

The amended Settlement Agreement does not, however, provide the Company with a full and complete release from potential further liability for remediation of the groundwater contamination. After the Company has expended the Settlement Amount, if the NMED can establish through binding arbitration that the Santa Fe Station is the source of the contamination, the Company could be required to perform further remediation that is determined to be necessary. The Company continues to dispute any contention that the Santa Fe Station is the source of the groundwater contamination and believes that insufficient data exists to identify the sources of groundwater contamination. The Company has completed an aquifer characterization report and a groundwater quality report associated with the 40 day reactivation of the adjacent Santa Fe supply well in July and August of 1996. These reports strongly suggest the groundwater contamination does not originate from the Santa Fe Station site and has been drawn under the site by the pumping of the Santa Fe supply well. In addition, other urban wells in Santa Fe are likely to be vulnerable to contamination from off-site sources.

The Company and the NMED, with the cooperation of the City of Santa Fe, have chosen a remediation plan proposed by a remediation contractor. The City of Santa Fe, the Company and the NMED have entered into a Memorandum of Understanding concerning the chosen remediation plan and the operation of the municipal well adjacent to the Santa Fe Station site in connection with carrying out that plan. Construction of the remediation system under the plan is expected to commence in the second quarter of 1998. The system is expected to be in operation early in the third quarter of 1998.

Person Generating Station ("Person Station")

The Company, in compliance with the NMED's Corrective Action Directive, determined that groundwater contamination exists in the deep and shallow groundwater at the Person Station site. The Company is required to delineate the extent of the contamination and remediate the contaminants in the groundwater at the Person Station site. The extent of the contaminant plume in the deep groundwater was assessed and results were reported to the NMED. The Company currently is involved with the process to renew the Resource Conservation and Recovery Act ("RCRA") post-closure care permit for the facility. Remedial actions for the deep groundwater will be incorporated into the new permit. The Company has proposed a monitoring program in conjunction with natural attenuation processes as the most cost effective approach for the deep groundwater remediation. The Company's current estimate to decommission its retired fossil-fueled plants includes approximately $6.3 million in additional expenses to complete the groundwater remediation program at Person Station. As part of the financial assurance requirement of the Person Station Hazardous Waste Permit, the Company established a trust fund. The current value of the trust fund at December 31, 1997, was $7.3 million. The remediation program continues on schedule.

GAS OPERATIONS

Gas Wellhead Pit Remediation

The New Mexico Oil Conservation Commission ("OCD") issued an order, effective on January 14, 1993, that affects the gas gathering facilities located in the San Juan Basin in northwestern New Mexico. The Bureau of Land Management ("BLM") has issued a similar order. The order prohibits the further discharge of fluids associated with the production of natural gas into unlined earthen pits in specified areas (designated as "vulnerable areas") in the San Juan Basin. The order also required the submission of closure plans for the pits where further discharge was prohibited. The Company has complied with the orders and has submitted and received approval for pit closures from the OCD and the BLM.

These gas gathering facilities were sold to Williams Gas Processing - Blanco, Inc., a subsidiary of the Williams Fields Services Group, Inc., of Tulsa, Oklahoma ("Williams") on June 30, 1995. As a part of the purchase and sale agreement, the Company agreed to cease discharge to unlined earthen pits in designated vulnerable areas and to retain the responsibility for pit closures for a stated period of time and to a stated dollar amount. The Company has assessed the pits in accordance with OCD/BLM directives, and is now in the process of closing pits and remediating them, if necessary, at wellhead locations within the designated vulnerable areas. The Company has submitted a groundwater management plan to the OCD and has received approval of the plan, and is proceeding with delineation of groundwater contamination and, as necessary, cleanup, in accordance with the approved plan. The Company will address soil and groundwater contamination within the dollar and time limitations imposed by the purchase and sale agreement with Williams, and in accordance with the requirements of the OCD.

In March 1995, the Jicarilla Apache Tribe ("Jicarilla") enacted an ordinance directing that unlined surface impoundments located within environmentally sensitive areas be remediated and closed by December 1996, and that all other unlined surface impoundments on Jicarilla lands be remediated and closed by December 1998. In 1995, the Company received a claim for indemnification by Williams, the purchaser of the Company's gas gathering and processing assets, for the environmental work required to comply with the Jicarilla ordinance. The Company submitted a closure/remediation plan to the Jicarillas, which was approved. The Company's remediation work pursuant to the plan commenced in mid-1996, and the costs of remediation are being charged against the $10.6 million indemnification cap contained in the purchase and sale agreement between the Company and Williams. The Company met the requirement for closing and remediating pits within the environmentally sensitive area by December 1996, and anticipates closing and remediating all other pits associated with the gas gathering and processing assets by the December 1998 deadline specified in the ordinance.

COAL FUEL SUPPLY

The coal requirements for SJGS are being supplied by San Juan Coal Company ("SJCC"), a wholly owned subsidiary of BHP Minerals International, Inc. ("BHP"), from certain Federal, state and private coal leases under a Coal Sales Agreement, pursuant to which SJCC will supply processed coal for operation of SJGS until 2017. The primary sources of coal are a mine adjacent to SJGS and a mine located approximately 25 miles northeast of SJGS in the La Plata area of northwestern New Mexico.

During the third quarter of 1997, the Company was notified by SJCC of certain audit exceptions identified by the Federal Minerals Management Service for the period 1986 through 1997. These exceptions pertain to the valuation of coal for purposes of calculating the Federal coal royalty. Primary issues include whether coal processing and transportation costs should be included in the base value of La Plata coal for royalty determination. In addition, the Company was notified of claims by a private royaltyholder involving royalty valuation at the La Plata Mine. The Company is currently assessing the potential impact to the Company and the validity of the audit exceptions and claims.

In 1996, the Company was notified by BHP, fuel supplier to SJGS, that the Navajo Nation has proposed to select certain properties within the San Juan and La Plata Mines (the "mining properties") pursuant to the Navajo-Hopi Land Settlement Act of 1974 (the "Act"). The mining properties are operated by BHP under leases from the BLM and comprise a portion of the fuel supply for SJGS. An administrative appeal by BHP is pending. In the appeal, BHP expressed concern that transfer of the mining properties to the Navajo Nation may subject the mining operations to taxation and additional regulation by the Navajo Nation, both of which could increase the price of coal that might potentially be passed on to SJGS through the existing Coal Sales Agreement. A stay of all actions by the BLM has been ordered by the Interior Board of Land Appeals pending resolution of the issues on appeal. The Company is monitoring closely the appeal and other developments on this issue and will continue to assess potential impacts to SJGS and the Company's operations. Currently, the Company is unable to predict the ultimate outcome of this matter but does not believe it will have a material adverse effect on the Company's financial condition or results of operations.

ACCOUNTING FOR THE EFFECTS OF CERTAIN TYPES OF REGULATION

As described in note 3 to the consolidated financial statements, the Company is subject to the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation.* In the event the Company determines that it no longer meets the criteria for following SFAS No. 71, the accounting impact would be an extraordinary, non-cash charge to operations of an amount that could be material. Criteria that may give rise to the discontinuance of SFAS No. 71 include: (1) increasing competition that restricts the Company's ability to establish prices to recover specific costs and (2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure that the continuing application of SFAS No. 71 is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its regulatory assets (net of related regulatory liabilities), including those related to generation, are probable of future recovery.

ACCOUNTING STANDARDS

Environmental Remediation Liabilities. Effective January 1, 1997, the Company adopted the provisions of the American Institute of Certified Public Accountants' Statement of Position ("SOP") 96-1, *Environmental Remediation Liabilities.* This Statement provides authoritative guidance for recognition, measurement, display and disclosure of environmental remediation liabilities in financial statements. The Company previously recorded environmental liabilities of $24.0 million for its retired fossil-fueled plants. Approximately $14.4 million of the $24.0 million has been expended through December 31, 1997. The adoption of SOP 96-1 did not have a material impact on the Company's financial position or results of operations.

Nuclear Plant Decommissioning. The staff of the Securities and Exchange Commission ("SEC") has questioned certain of the current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in financial statements of electric utilities. In response to these questions, the Financial Accounting Standards Board ("FASB") has added a project to its agenda to review the accounting for closure and removal costs, including decommissioning of nuclear power plants. If current electric utility industry accounting practices for nuclear power plant decommissioning are changed, the annual provision for decommissioning could increase relative to 1996, and the estimated cost for decommissioning could be recorded as a liability (rather than as accumulated depreciation), with recognition of an increase in the cost of the related nuclear power plant. The Company does not believe that such changes, if required, would have a material adverse effect on results of operations.

Reporting Comprehensive Income and Disclosure about Segments of an Enterprise and Related Information. During 1997, FASB issued SFAS No. 130, *Reporting Comprehensive Income* and SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.* These statements are not effective until 1998. SFAS No. 130 requires the reporting and display of comprehensive income and its components in financial statements. The objective of this statement is to report a measure of all changes in equity that resulted from transactions and other economic events of the period other than transactions with owners. Comprehensive income is the total of net income and all other nonowner changes in equity. SFAS No. 131 requires a public company to report selected information about its reportable operating segments in annual and interim condensed financial statements. This statement introduces a new model for segment reporting, called the "management approach" for identifying operating segments. Operating segments are components of an enterprise for which discrete financial information is available, that is evaluated regularly by the chief operating decision-maker within a company in order to make operating decisions and assess performance.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

The Private Securities Litigation Reform Act of 1995 (the "Act") provides a "safe harbor" for forward-looking statements to encourage companies to provide prospective information about their companies without fear of litigation so long as those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause actual results to differ materially from those projected in the statement. Accordingly, the Company hereby identifies the following important factors which could cause the Company's actual financial results to differ materially from any such results which might be projected, forecasted, estimated or budgeted by the Company in forward-looking statements: (i) adverse actions of utility regulatory commissions; (ii) utility industry restructuring; (iii) failure to recover stranded assets; (iv) failure to obtain new customers or retain existing customers; (v) inability to carry out marketing and sales plans; (vi) adverse impacts resulting from environmental regulations; (vii) loss of favorable fuel supply contracts; (viii) failure to obtain water rights and rights-of-way; (ix) operational and environmental problems at generating stations; (x) weather conditions and (xi) failure to maintain adequate transmission capacity.

Many of the foregoing factors discussed have been addressed in the Company's previous filings with the SEC pursuant to the Securities Exchange Act of 1934. The foregoing review of factors pursuant to the Act should not be construed as exhaustive or as any admission regarding the adequacy of disclosures made by the Company prior to the effective date of the Act.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Public Service Company of New Mexico (the "Company") is responsible for the preparation and presentation of the accompanying consolidated financial statements. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles and include amounts that are based on informed estimates and judgments of management. Management maintains a system of internal accounting controls which it believes is adequate to provide reasonable assurance that assets are safeguarded, transactions are executed in accordance with management authorization and the financial records are reliable for preparing the consolidated financial statements. The system of internal accounting controls is supported by written policies and procedures, by a staff of internal auditors who conduct comprehensive internal audits and by the selection and training of qualified personnel. The board of directors, through its audit committee comprised entirely of outside directors, meets periodically with management, internal auditors and the Company's independent auditors to discuss auditing, internal control and financial reporting matters. To ensure their independence, both the internal auditors and independent auditors have full and free access to the audit committee. The independent auditors, Arthur Andersen LLP, are engaged to audit the Company's consolidated financial statements in accordance with generally accepted auditing standards.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Stockholders of Public Service Company of New Mexico:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Public Service Company of New Mexico (a New Mexico corporation) and subsidiaries as of December 31, 1997 and 1996, and the related consolidated statements of earnings, retained earnings (deficit), and cash flows for each of the three years in the period ended December 31, 1997. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Public Service Company of New Mexico and subsidiaries as of December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997 in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

Albuquerque, New Mexico
February 10, 1998

CONSOLIDATED STATEMENTS OF EARNINGS

	YEAR ENDED DECEMBER 31,		
	1997	1996	1995
	(In thousands except per share amounts)		
Operating Revenues:			
Electric	$ 722,438	$ 645,639	$ 584,284
Gas	294,769	227,301	217,985
Energy Services	118,060	10,446	-
Water	-	-	6,196
Total operating revenues	1,135,267	883,386	808,465
Operating Expenses:			
Fuel and purchased power	235,508	178,807	140,752
Gas purchased for resale	169,758	103,574	94,299
Gas purchased for resale and other - Energy Services	121,728	9,485	-
Other operation expenses	273,692	263,432	257,627
Maintenance and repairs	52,629	49,694	55,809
Depreciation and amortization	82,702	78,116	80,865
Taxes, other than income taxes	36,871	34,864	35,531
Income taxes	38,334	39,395	30,194
Total operating expenses	1,011,222	757,367	695,077
Operating income	124,045	126,019	113,388
Other Income and Deductions:			
Other	21,548	2,367	40,707
Income tax expense	(8,384)	(1,099)	(20,599)
Net other income and deductions	13,164	1,268	20,108
Income before interest charges	137,209	127,287	133,496
Interest Charges:			
Interest on long-term debt	46,670	49,009	52,637
Other interest charges	9,544	5,698	5,297
Net interest charges	56,214	54,707	57,934
Net Earnings	80,995	72,580	75,562
Preferred Stock Dividend Requirements	586	586	3,714
Net Earnings Available for Common Stock	$ 80,409	$ 71,994	$ 71,848
Average Number of Common Shares Outstanding	41,774	41,774	41,774
Net Earnings per Common Share (Basic)	$ 1.92	$ 1.72	$ 1.72
Net Earnings per Common Share (Diluted)	$ 1.91	$ 1.71	$ 1.72
Dividends Paid per Share of Common Stock	$ 0.63	$ 0.36	$ -

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT)

	YEAR ENDED DECEMBER 31,		
	1997	1996	1995
	(In thousands)		
Balance at Beginning of Year	$ 77,185	$ 25,243	$ (46,006)
Net earnings	80,995	72,580	75,562
Redemption of cumulative preferred stock	-	-	(599)
Dividends:			
Cumulative preferred stock	(586)	(586)	(3,714)
Common stock	(28,406)	(20,052)	-
Balance at End of Year	$ 129,188	$ 77,185	$ 25,243

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

CONSOLIDATED BALANCE SHEETS

ASSETS

	YEAR ENDED DECEMBER 31, 1997	1996
	(In thousands)	
Utility Plant, at original cost except PVNGS:		
Electric plant in service	$1,958,912	$1,918,238
Gas plant in service	441,045	424,827
Energy services plant in service	-	1,241
Common plant in service	43,415	40,005
Plant held for future use	551	639
	2,443,923	2,384,950
Less accumulated depreciation and amortization	1,003,086	937,228
	1,440,837	1,447,722
Construction work in progress	104,497	76,038
Nuclear fuel, net of accumulated amortization of $21,263 and $20,413	27,816	28,933
Net utility plant	1,573,150	1,552,693
Other Property and Investments:		
Non-utility property, net of accumulated depreciation of $2,146 and $1,774	4,502	3,434
Other investments, at cost	300,438	250,834
Total other property and investments	304,940	254,268
Current Assets:		
Cash	8,705	11,125
Temporary investments, at cost	9,490	9,128
Receivables, net of allowance for uncollectible accounts of $783 and $709	216,305	197,025
Income taxes receivable	-	18,825
Fuel, materials and supplies, at average cost	33,664	41,260
Gas in underground storage, at average cost	13,158	2,679
Other current assets	4,509	6,632
Total current assets	285,831	286,674
Deferred charges	149,811	136,679
	$2,313,732	$2,230,340

CAPITALIZATION AND LIABILITIES

	1997	1996
Capitalization:		
Common stock equity:		
Common stock outstanding — 41,774 shares	$ 208,870	$ 208,870
Additional paid-in capital	469,073	470,358
Excess pension liability, net of tax	(2,727)	(2,102)
Retained earnings since January 1, 1989	129,188	77,185
Total common stock equity	804,404	754,311
Cumulative preferred stock without mandatory redemption requirements	12,800	12,800
Long-term debt, less current maturities	713,995	713,919
Total capitalization	1,531,199	1,481,030
Current Liabilities:		
Short-term debt	114,100	100,400
Accounts payable	154,501	130,661
Dividends payable	7,248	5,159
Current maturities of long-term debt	350	14,970
Accrued interest and taxes	24,161	23,356
Other current liabilities	26,102	25,477
Total current liabilities	326,462	300,023
Deferred Credits:		
Accumulated deferred investment tax credits	57,823	62,258
Accumulated deferred income taxes	121,353	110,266
Other deferred credits	276,895	276,737
Total deferred credits	456,071	449,261
Commitments and Contingencies		
	$2,313,732	$2,230,314

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31,		
	1997	1996	1995
		(In thousands)	
Cash Flows From Operating Activities:			
Net earnings	$ 80,995	$ 72,580	$ 75,562
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	94,924	90,458	92,588
Accumulated deferred investment tax credit	(4,436)	(4,476)	(4,830)
Accumulated deferred income taxes	11,080	31,436	1,622
Gain on sale of utility property	-	(309)	(39,050)
Write-down of natural gas vehicle program	-	2,810	1,445
Curtailment gain on defined benefit pension plan	-	(13,316)	-
Changes in certain assets and liabilities:			
Receivables	4,554	(83,416)	795
Fuel, materials and supplies	(2,883)	5,795	(26,505)
Deferred charges	(11,190)	5,190	6,731
Accounts payable	23,808	36,930	(11,527)
Accrued interest and taxes	805	(3,500)	(1,218)
Deferred credits	2,455	12,655	29,185
Other	(371)	(9,279)	5,645
Other, net	13,381	22,343	17,671
Net cash flows from operating activities	213,122	165,901	148,114
Cash Flows From Investing Activities:			
Utility plant additions	(128,371)	(103,087)	(107,666)
Increase in nuclear decommissioning trust	(23,000)	-	-
Return of principal of PVNGS lease obligation bonds	5,018	-	-
Utility plant sales	-	333	206,482
Other property sales	-	702	(801)
Net increase in other property and investments	(6,814)	(14,706)	-
Escrow for purchase of PVNGS lease obligation bonds	(28,900)	(208,446)	-
Decrease (increase) in temporary investments, net	(363)	86,844	(21,451)
Net cash flows from investing activities	(182,430)	(238,360)	76,564
Cash Flows From Financing Activities:			
Redemption of PVNGS lease obligation bonds	-	-	(132,663)
Redemptions and repurchases of preferred stock	-	-	(64,175)
Bond redemption premium and costs	(3,693)	(5,158)	(505)
Proceeds from (repayments of) asset securitization	(13,900)	100,400	18,758
Repayments of long-term debt	(14,970)	(326)	(57,768)
Trust borrowing for nuclear decommissioning	23,000	-	-
Increase in short-term debt	4,600	-	-
Exercise of employee stock options	(1,285)	-	-
Dividends paid	(26,864)	(15,560)	(5,126)
Net cash flows from financing activities	(33,112)	79,356	(241,479)
Increase (Decrease) in Cash	(2,420)	6,897	(16,801)
Cash at Beginning of Year	11,125	4,228	21,029
Cash at End of Year	$ 8,705	$ 11,125	$ 4,228
Supplemental cash flow disclosures:			
Interest paid	$ 57,302	$ 55,480	$ 63,366
Income taxes paid, net of refunds	$ 20,175	$ 31,617	$ 52,405

Cash consists of currency on hand and demand deposits.

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

				Year Ended December 31, 1997	1996
				(In thousands)	
Common Stock Equity:					
Common Stock, par value $5 per share				$ 208,870	$ 208,870
Additional paid-in capital				469,073	470,358
Excess pension liability, net of tax				(2,727)	(2,102)
Retained earnings since January 1, 1989				129,188	77,185
Total common stock equity				804,404	754,311
	Stated Value	Shares Outstanding at December 31, 1997	Current Redemption Price		
Cumulative Preferred Stock:					
Without mandatory redemption requirements:					
1965 Series, 4.58%	$100.00	128,000	$102.00	12,800	12,800
Long-Term Debt:					
Issue and Final Maturity		Interest Rates			
First mortgage bonds:					
1997		5 7/8%		-	14,650
1999 through 2002		7 1/4% to 8 1/8%		42,556	42,876
2005 through 2007		8 1/8% to 9 1/8%		43,276	43,276
2008		9 %		54,374	54,374
Pollution control revenue bonds:					
2007 through 2026		5.7% to 6 1/2%		574,345	537,045
2022		Variable rate		-	37,300
Total first mortgage bonds				714,551	729,521
Other, including unamortized premium and (discount), net				(206)	(632)
Total long-term debt				714,345	728,889
Less current maturities				350	14,970
Long-term debt, less current maturities				713,995	713,919
Total Capitalization				$1,531,199	$1,481,030

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 1997, 1996 and 1995

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Public Service Company of New Mexico (the "Company") is an investor-owned utility company engaged in the generation, transmission, distribution and sale of electricity. The Company provides retail electric service to a large area of north central New Mexico, including the cities of Albuquerque, Santa Fe, Rio Rancho, Las Vegas, Belen and Bernalillo. The City of Albuquerque ("COA"), Bernalillo County and the City of Las Vegas franchises expired in 1992, 1997 and 1996, respectively. Customers in the area covered by the expired franchises represent approximately 40.2%, 8.6% and 1.2%, respectively, of the Company's 1997 total electric operating revenues, and no other franchise area represents more than 6.1%. The Company continues to collect and pay franchise fees to both the COA and the City of Las Vegas. The Company currently does not pay franchise fees to Bernalillo County. The Company remains obligated under state law to provide service to customers in the franchise area even in the absence of a franchise agreement. The Company also provides retail electric service to Deming in southwestern New Mexico and to Clayton in northeastern New Mexico. The Company is also engaged in the transmission, distribution and sale of natural gas within the State of New Mexico. The Company distributes natural gas to most of the major communities in New Mexico, including Albuquerque and Santa Fe. In addition, in pursuing new business opportunities, the Company is focusing on energy and utility related activities under its Energy Services Business Unit. These activities will provide energy marketing and energy management services, the marketing of natural gas outside of New Mexico, management services for water and wastewater systems and utility related management and operation services for Federal installations and other large commercial institutions. The Company is also operating the City of Santa Fe's water system.

Systems of Accounts

The Company maintains its accounts for utility operations primarily in accordance with the uniform systems of accounts prescribed by the FERC and the National Association of Regulatory Utility Commissioners, and adopted by the NMPUC.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and subsidiaries in which it owns a majority voting interest. All significant intercompany transactions and balances have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual recorded amounts could differ from those estimated.

Utility Plant

Utility plant, with the exception of PVNGS Unit 3 and the Company's purchased 22% beneficial interests in the PVNGS Units 1 and 2 leases, is stated at original cost, which includes capitalized payroll-related costs such as taxes, pension and other fringe benefits, administrative costs and an allowance for funds used during construction. Utility plant includes certain electric assets not subject to regulation. The results of operations of such electric assets are included in operating income.

It is Company policy to charge repairs and minor replacements of property to maintenance expense and to charge major replacements to utility plant. Gains or losses resulting from retirements or other dispositions of operating property in the normal course of business are credited or charged to the accumulated provision for depreciation.

Depreciation and Amortization

Provision for depreciation and amortization of utility plant is made at annual straight-line rates approved by the NMPUC. The average rates used are as follows:

	1997	1996	1995
Electric plant	3.33%	3.32%	3.32%
Gas plant	3.23%	3.27%	3.21%
Common plant	7.60%	7.00%	9.61%

Effective January 1, 1995, electric plant depreciation rates were revised and include a provision for the recovery of fossil-fueled plant decommissioning costs approved by the NMPUC in 1994. Gas plant depreciation rates were approved by the NMPUC and revised in March 1997.

The provision for depreciation of certain equipment is charged to clearing accounts and subsequently allocated to operating expenses or construction projects based on the use of the equipment. Depreciation of non-utility property is computed on the straight-line method. Amortization of nuclear fuel is computed based on the units of production method.

Nuclear Decommissioning

The Company accounts for nuclear decommissioning costs on a straight-line basis over the estimated useful life of the facilities. Such amounts are based on the net present value of expenditures estimated to be required to decommission the plant.

Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC")

The Company uses the deferral method of accounting for fuel and purchased power costs for its firm-requirements wholesale customers. Such amounts are reflected in subsequent periods under a FPPCAC approved by the FERC.

Purchased Gas Adjustment Clause ("PGAC")

The Company uses the deferral method of accounting for gas purchase costs which are settled in subsequent periods under gas adjustment clauses. Future recovery of these costs is subject to approval by the NMPUC.

Amortization of Debt Discount, Premium and Expense

Discount, premium and expense related to the issuance of long-term debt are amortized over the lives of the respective issues. In connection with the retirement of long-term debt, such amounts associated with resources subject to NMPUC regulation are amortized over the lives of the respective issues. Amounts associated with the Company's firm-requirements wholesale customers and its resources excluded from NMPUC retail rates are recognized immediately as expense or income as they are incurred.

Income Taxes

The Company reports income tax expense in accordance with SFAS No. 109, *Accounting for Income Taxes*. SFAS No. 109 requires deferred income taxes for temporary differences between financial and income tax reporting to be recorded using the liability method. Deferred income taxes are computed using the statutory tax rates scheduled to be in effect when the temporary differences reverse. Current NMPUC jurisdictional rates include the tax effects of the majority of these temporary differences (normalization). Recovery of reversing temporary differences previously accounted for under the flow-through method is also included in rates charged to customers. For regulated operations, any changes in tax rates applied to accumulated deferred income taxes may not be immediately recognized because of ratemaking and tax accounting provisions contained in the Tax Reform Act of 1986. Items accorded flow-through treatment under NMPUC orders, deferred income taxes and the future ratemaking effects of such taxes, as well as corresponding regulatory assets and liabilities, are recorded in the financial statements.

Accounting Standards

Environmental Remediation Liabilities. Effective January 1, 1997, the Company adopted the provisions of The American Institute of Certified Public Accountants Statement of Position ("SOP") 96-1, *Environmental Remediation Liabilities*. This Statement provides authoritative guidance for recognition, measurement, display and disclosure of environmental remediation liabilities in financial statements. The Company previously recorded environmental liabilities of $24.0 million for its retired fossil-fueled plants. Approximately $14.4 million of the $24.0 million has been expended as of December 31, 1997. The adoption of SOP 96-1 did not have a material impact on the Company's financial position or results of operations.

Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities. In June 1996, the FASB issued SFAS No. 125, *Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities*. This Statement establishes, among other things, new criteria for determining whether a transfer of financial assets should be accounted for as a sale or as a pledge of collateral in a secured borrowing. SFAS No. 125 also establishes new accounting requirements for pledged collateral. SFAS No. 125 is effective for all transfers and servicing of financial assets and extinguishments of liabilities occurring after December 31, 1996, is to be applied prospectively, and earlier or retroactive application is not permitted.

Nuclear Plant Decommissioning. The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in financial statements of electric utilities. In response to these questions, the FASB has added a project to its agenda to review the accounting for closure and removal costs, including decommissioning of nuclear power plants. If current electric utility industry accounting practices for nuclear power plant decommissioning are changed, the annual provision for decommissioning could increase relative to 1997, and the estimated cost for decommissioning could be recorded as a liability (rather than as accumulated depreciation), with recognition of an increase in the cost of the related nuclear power plant. The Company does not believe that such changes, if required, would have a material adverse effect on results of operations.

Risk Management Activities

The Company's Board of Directors ("Board") approved a Corporate policy statement regarding risk management activities. The Company is exposed to market risk from changes in certain energy related commodity prices. Although the Company is allowed to enter into certain derivative transactions to manage the volatility relating to the price exposure, the Company did not use derivative financial instruments to hedge this price risk exposure during 1997. Because market prices of certain energy commodities depend on a number of unpredictable factors, such as weather, the Company is currently managing the resulting volatility using commodities contracts. Beginning in 1998, the Company is planning to use derivative financial instruments, including exchange-traded financial futures, options, swaps and other derivative financial instruments as part of an overall risk-management strategy. These instruments are to be used only as a means of hedging exposure to price and interest-rate risk connected to anticipated transactions or existing assets and liabilities. The Company does not intend to open a derivative position for speculative purposes.

Once the Company enters into derivative transactions, deferral (hedge) accounting will be applied only if the derivative financial instrument reduces the risk of the underlying hedged item and is designated at inception as a hedge with respect to the hedged item. Additionally, the derivative must result in payoffs that are expected to be inversely correlated to those of the hedged item. Correlation will be assessed monthly and measured on a rolling three month average. If a derivative instrument ceases to meet the criteria for deferral or settlement accounting, any subsequent gains and losses will be recognized in income. If a hedging instrument is sold or terminated prior to maturity, gains and losses will continue to be deferred until the hedged item is recognized in income.

Performance Stock Plan

The Company continues to apply Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for its plan. Accordingly, no compensation cost has been recognized for its fixed stock option plan.

(2) RISKS AND UNCERTAINTIES

Competition and restructuring of the electric utility industry continue to be key issues facing the Company. Efforts to advance and determine the eventual form of industry restructuring continued during 1997.

At the state level, the Company proposed in April 1997 that the NMPUC reconvene the proceedings involving the NMPUC's Notice of Inquiry into the restructuring of the electric industry, in an attempt to arrive at consensus legislation to be presented to the 1998 session of the New Mexico Legislature. In May 1997, the NMPUC issued an order accepting the Company's proposal for a collaborative effort, and the proposal for a series of meetings to be held among all interested parties. The parties held several meetings in which the Company actively participated. However, in September 1997, the collaborative process to draft legislation was declared at an impasse due to disagreement on issues regarding the divestiture of generation and energy service units from electric distribution and transmission systems, and the recoverability of stranded costs.

Although the parties could not reach agreement, the Company filed its own proposal for industry restructuring in September 1997 with both the NMPUC, and the Water, Utilities & Natural Resources Committee ("WUNR") of the New Mexico Legislature.

The Company's proposal called for an immediate rate reduction of $10 million per year for residential customers from the effective date of proposed legislation until open access without the need for a rate case. The proposal also called for full retail competition no later than January 1, 2001. Other parts of the Company's proposal included an offer to create a regulated distribution "wires and pipes" company dedicated only to the delivery of electricity and natural gas. Other services, usually associated with distribution, such as meter reading, billing and customer services would be provided through competitive markets. The Company offered to assume the risk of stranded cost recovery on all fossil fuel generation and on PVNGS Unit 3 which was previously excluded from New Mexico jurisdictional rates. However, the Company would recover all fixed costs associated with PVNGS Units 1 and 2 through a non-bypassable "wires charge" from 2001 to 2016. The proposal also called for certain credits to stranded costs which would effectively shorten the time period for recovery. The Company currently estimates that if the market clearing price for power, which represents the cost of generation at the plant, fell to 3.0 cents/KWh, it may incur an after-tax write-off of approximately $176 million related to its fossil fuel generation if the Company assumes this risk. The Company's proposal was supported by various parties to the collaborative process, including Enron Corporation, the New Mexico Retail Association, Southwestern Public Service Company ("SPS"), the United States Executive Agencies and the International Brotherhood of Electrical Workers. However, the Company's proposal was not adopted by the WUNR and not introduced during the 1998 legislative session. The WUNR declined to recommend any restructuring legislation as a committee bill during the 1998 legislative session.

On January 22, 1998, the NMPUC submitted its own report to the New Mexico Legislature related to restructuring of the electric utility industry. The following key points were included in the report: (i) PVNGS and Plains Escalante Generating Station are the most debated issues in deregulation because of their potential stranded costs; (ii) stranded costs, if determined to be lawful, should be verified by the NMPUC or its successor, the Public Regulation Commission ("PRC"); (iii) market power issues may be addressed through functional separation or partial or complete divestiture of generation, transmission and distribution; (iv) unbundling is necessary to understand the disparities among various electricity providers; (v) despite an abundance of natural resources to fuel generation facilities, New Mexico customers pay more for electricity because of costs associated with generation plants; (vi) on average, New Mexico residential customers pay more for electricity than regional and national residential customers and (vii) system reliability must be maintained or enhanced, and customers must be educated and environmental protections should be promoted. In addition, sample legislation was attached to the report, giving either the NMPUC or the PRC authority to conclude matters relating to electric industry restructuring. The report was issued as a result of a NMPUC case and, with the issuance of the report, the case was closed. The NMPUC's draft legislation was not introduced during the 1998 legislative session. House Memorial 27, the only measure dealing with restructuring, passed the House. Memorial 27 stated the intent of the legislature to address the issue of electric industry restructuring in the 1999 session and declared that the NMPUC does not have statutory authority to implement restructuring at this time. The Memorial 27 did not require concurrence by the Senate; however, an identical Senate Memorial was not acted upon by the full Senate prior to adjournment.

In a related matter, in 1996, the NMPUC ordered all utilities under its jurisdiction to file their estimates of stranded costs, absent any recovery method being adopted, based on the Texas Public Utility Commission Economic Cost Over Market ("ECOM") model. The Company, in its filing, presented two methodologies: (i) using the ECOM model, the Company's stranded cost estimates run from $657 million for a 1998 full retail access case to $119 million for a 2002 full retail access case and (ii) using a second methodology, based upon the difference between the Company's costs of existing generation and the costs of new combined cycle and combustion turbine units to serve the same load, the Company's costs above the level of new gas units, in 1997 dollars, were estimated at $748 million for a 1998 full retail access case to $327 million for a 2002 full retail access case. The Company advised the NMPUC that the results of the ECOM model are highly sensitive to various assumptions, primarily projections of future gas prices. This information was addressed in the NMPUC's report submitted to the New Mexico Legislature.

(3) REGULATORY ASSETS AND LIABILITIES

The Company is subject to the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, on operations regulated by the NMPUC. Regulatory assets represent probable future revenue to the Company associated with certain costs which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Regulatory assets and liabilities reflected in the Consolidated Balance Sheets as of December 31 relate to the following:

	1997	1996
	(In thousands)	
Deferred Income Taxes	$ 70,968	$ 71,682
Gas Take-or-Pay Costs	19,953	36,335
PGAC	16,006	28,873
Gas Imputed Revenues	12,823	10,362
Loss on Reacquired Debt	8,869	7,850
Gas Reservation Fees	7,029	7,029
Gas Retirees' Health Care Costs	6,345	4,437
Deferred Customer Expense on Gas Assets Sale	5,260	5,260
Proposed Transmission Line Costs	2,903	3,111
EPNG Risk Sharing Surcharge	2,196	-
Gas Rate Case Costs	1,571	1,571
Other	118	598
Subtotal	154,041	177,108
Deferred Income Taxes	(53,132)	(56,961)
Gas Regulatory Reserve	(27,881)	(24,614)
Customer Gain on Gas Assets Sale	(11,856)	(22,230)
PVNGS Prudence Audit	(6,561)	(6,937)
Revenue Subject to Refund	(3,896)	(3,594)
Settlement Due Customers	(3,743)	(4,072)
EPNG Risk Sharing Surcharge	(2,196)	-
Other	(723)	-
Gain on Reacquired Debt	(546)	(559)
Subtotal	(110,534)	(118,967)
Net Regulatory Assets	$ 43,507	$ 58,141

As of December 31, 1997, substantially all of the Company's regulatory assets and regulatory liabilities are being recovered in rates charged to customers or have been addressed in a regulatory proceeding. If a portion of the Company's operations under the NMPUC jurisdiction becomes no longer subject to the provisions of SFAS No. 71, a write-off of related regulatory assets and liabilities would be required, unless some form of transition cost recovery (refund) continues through rates established and collected for the Company's remaining regulated operations. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its regulatory assets are probable of future recovery.

Effective January 1, 1996, the Company adopted SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed Of.* This statement imposes a stricter criterion for regulatory assets by requiring that such assets be probable of future recovery at each balance sheet date. Based on the current regulatory structure in which the Company operates, adoption of this standard did not have a material impact on the Company's financial position or results of operations. However, the Company's ability to meet the criterion may change in the future as competitive factors influence wholesale and retail pricing in this industry.

(4) CAPITALIZATION

Changes in common stock, additional paid-in capital and cumulative preferred stock are as follows:

	Common Stock			Cumulative Preferred Stock Without Mandatory Redemption Requirements	
	Number of Shares	Aggregate Par Value	Additional Paid-In Capital	Number of Shares	Aggregate Stated Value
	(Dollars in thousands)				
Balance at December 31, 1995 and 1996	41,774,083	$208,870	$470,358	128,000	$12,800
Exercise of stock options	-	-	(1,285)	-	-
Balance at December 31, 1997	41,774,083	$208,870	$469,073	128,000	$12,800

Common Stock

The number of authorized shares of common stock with par value of $5 per share is 80 million shares.

On December 9, 1997, the Company's Board declared a quarterly cash dividend of 17 cents per share of common stock payable February 20, 1998 to shareholders of record as of February 2, 1998. The Company resumed the payment of cash dividends on common stock starting in May 1996. The Company's Board reviews the Company's dividend policy on a continuing basis. The declaration of common dividends is dependent upon a number of factors including earnings and financial condition of the Company and market conditions.

On September 16, 1996, the Company implemented a dividend reinvestment and stock purchase plan for investors, including customers and employees. The plan, called PNM Direct, also includes safekeeping services and automatic investment features. The Company's stock is purchased in the open market to meet plan requirements.

Cumulative Preferred Stock

The number of authorized shares of cumulative preferred stock is 10 million shares. The Company has 128,000 shares, 1965 Series, 4.58%, stated value of $100 per share, of cumulative preferred stock outstanding. The 1965 Series does not have a mandatory redemption requirement but may be redeemable at 102% of the par value with accrued dividends. The holders of the 1965 Series are entitled to payment before holders of common stock in the event of any liquidation or dissolution or distribution of assets of the Company. In addition, the 1965 Series is not entitled to a sinking fund and cannot be converted into any other class of stock of the Company. The Company's restated articles of incorporation limit the amount of preferred stock which may be issued. The earnings test in the Company's restated articles of incorporation currently allows for the issuance of preferred stock.

Long-Term Debt

Substantially all utility plant is pledged to secure the Company's first mortgage bonds. A portion of certain series of long-term debt will be redeemed serially prior to their due dates. The issuance of first mortgage bonds by the Company is subject to earnings coverage and bondable property provisions of the Company's first mortgage bond indenture. The Company also has the capability under the mortgage indenture to issue first mortgage bonds on the basis of certain previously retired bonds and earnings.

The aggregate amounts (in thousands) of maturities for 1998 through 2002 on long-term debt outstanding at December 31, 1997 are as follows:

1998	$ 350
1999	$12,030
2000	$ 1,050
2001	$16,038
2002	$15,900

On February 21, 1997, the Company completed the refinancing of $190 million of pollution control revenue bonds issued by the City of Farmington, all maturing in April 2022. The $60 million 1978 Series A Pollution Control Revenue Bonds and the $40 million 1979 Series A Pollution Control Revenue Bonds were refinanced as variable rate bonds *(Pollution Control Revenue Refunding Bonds, $40 million 1997 Series A, $37 million 1997 Series B and $23 million 1997 Series C).* The initial variable rates were 3.35% for $40 million 1997 Series A and $37 million 1997 Series B, and 3.30% for $23 million 1997 Series C. The remaining $90 million 1979 Series A Pollution Control Revenue Bonds were refinanced with a fixed rate of 6.375% *(Pollution Control Revenue Refunding Bonds, 1997 Series D).* The effect of the refinancing resulted in a decrease in interest charges of approximately $1.1 million in 1997.

On December 1, 1997, the Company converted $137.3 million of pollution control revenue bonds from variable rate to fixed rates. Of the total, $100 million of City of Farmington bonds (Pollution Control Revenue Refunding Bonds, $40 million 1997 Series A, $37 million 1997 Series B, and $23 million 1997 Series C) were converted to a fixed rate of 5.80% and $37.3 million of Maricopa County, Arizona Pollution Control Corporation bonds (Pollution Control Revenue Refunding Bonds, $37.3 million 1992 Series A) were converted to a fixed rate of 5.75%. The City of Farmington bonds mature on April 1, 2022, and the Maricopa County, Arizona Pollution Control Corporation bonds mature on November 1, 2022.

Revolving Credit Facility and Other Credit Facilities

At December 31, 1997, the Company has a $100 million revolving credit facility (the "Facility") with an expiration date of June 30, 1998. The Company must pay commitment fees of 3/10% per year on the total amount of the Facility. The Company expects to renew the Facility before its expiration date with a five-year $300 million senior unsecured revolving credit facility ("Revolver"). The Company also has a $100 million credit facility, which expires on May 20, 2001, and is collateralized by the Company's electric and gas customer accounts receivable and certain amounts being recovered from gas customers relating to certain gas contract settlements. As of December 31, 1997, the Company had $130 million of available liquidity arrangements, consisting of $100 million from the Facility, $15 million from the accounts receivable securitization, and $15 million from local lines of credit.

In November 1997, the Company requested NMPUC approval to enter into the Revolver. In addition, the Company intends to borrow $140 million from the Revolver to retire all of its outstanding taxable first mortgage bonds. The Company also requested authority to exchange the first mortgage bonds currently collateralizing the outstanding $575 million of tax-exempt pollution control revenue bonds with senior unsecured notes ("SUNs").

After completion of these transactions, the 1947 Indenture of Mortgage and Deed of Trust would be extinguished, resulting in more administrative, financial and strategic flexibility for the Company. The extinguishment of the mortgage requires the consent of one party which has not yet consented and may not consent. Due to concern about the consent, the Company also requested NMPUC authority to leave an amended mortgage in place. Among other modifications, the mortgage would be amended such that only $111 million of tax-exempt pollution control revenue bonds would have the benefit of the lien. The property under the lien would be reduced and no future bonds could be issued under the mortgage. The SUNs are planned to be issued under an indenture containing a restriction on liens (except in certain limited circumstances) and certain other covenants and restrictions. With the exception of the $111 million of tax exempt pollution control revenue bonds secured by first mortgage bonds, the SUNs will be the senior debt of the Company. On February 16, 1998, the NMPUC issued an order approving these transactions. The Company is anticipating completion of these transactions in mid-March 1998.

Off-Balance Sheet Items

In October 1996, the Company purchased $200 million of the PVNGS Lease Obligation Bonds ("LOBs") at a premium with accrued interest and on December 30, 1997, the Company purchased $28.9 million of 10.15% Series PVNGS LOBs at a premium with accrued interest.

Although the PVNGS LOBs are off-balance sheet debt, these bonds are included in the calculation of the Company's debt to capitalization ratio as well as various financial coverage ratios by the major rating agencies. The purchase of the PVNGS LOBs is treated by the rating agencies as a defeasance of the bonds thereby resulting in an improvement to these ratios. The purchase of the PVNGS LOBs has also increased earnings in the form of interest income.

Fair Value of Financial Instruments

The estimated fair value of the Company's financial instruments (including current maturities) at December 31, is as follows:

	1997		1996	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(In thousands)			
Long-Term Debt	$714,345	$743,524	$728,889	$731,358
Decommissioning Trust Debt	$ 23,000	$ 23,000	$ –	$ –
Investment in PVNGS LOBs	$237,774	$236,049	$212,979	$211,327
Decommissioning Trust	$ 51,857	$ 53,900	$ 25,641	$ 25,600
Fossil-Fueled Plant Decommissioning Trust	$ 7,245	$ 7,273	$ 6,785	$ 6,785
Rabbi Trust	$ 10,080	$ 15,218	$ 10,087	$ 13,991

Fair value is based on market quotes provided by the Company's investment bankers.

The carrying amounts reflected on the consolidated balance sheets approximate fair value for cash, temporary investments, and receivables and payables due to the short period of maturity.

(5) EARNINGS PER SHARE

In 1997, the Company adopted SFAS No. 128, *Earnings per Share.* As a result, dual presentation of basic and diluted earnings per share has been presented in the Consolidated Statement of Earnings. The following reconciliation illustrates the impact on the share amounts of potential common shares and the earnings per share amounts:

	INCOME	SHARES	PER-SHARE AMOUNT
	(In thousands except per share amounts)		
December 31, 1997			
Net Earnings	$80,995		
Less: Preferred stock dividends	(586)		
Basic Earnings per Share			
Net earnings available for common stock	80,409	41,774	$1.92
Options issued		217	
Diluted Earnings per Share			
Net earnings available for common stock	$80,409	41,991	$1.91
December 31, 1996			
Net Earnings	$72,580		
Less: Preferred stock dividends	(586)		
Basic Earnings per Share			
Net earnings available for common stock	71,994	41,774	$1.72
Options issued		332	
Diluted Earnings per Share			
Net earnings available for common stock	$71,994	42,106	$1.71
December 31, 1995			
Net Earnings	$75,562		
Less: Preferred stock dividends	(3,714)		
Basic earnings per share			
Net earnings available for common stock	71,848	41,774	$1.72
Options issued	–	103	
Diluted earnings per share			
Net earnings available for common stock	$71,848	41,877	$1.72

The adoption of SFAS No. 128 did not have an impact on previously reported earnings per share (basic).

(6) INCOME TAXES

Income taxes consist of the following components:

	1997	1996	1995
		(In thousands)	
Current Federal income tax	$ 32,911	$ 14,815	$ 45,940
Current state income tax	9,859	2,847	5,864
Deferred Federal income tax	8,781	22,372	(3,212)
Deferred state income tax	(397)	4,936	7,031
Amortization of accumulated investment tax credits	(4,436)	(4,476)	(4,442)
Recognition of accumulated deferred investment tax credits relating to sales of utility property	-	-	(388)
Total income taxes	$ 46,718	$ 40,494	$ 50,793
Charged to operating expenses	$ 38,334	$ 39,395	$ 30,194
Charged to other income and deductions	8,384	1,099	20,599
Total income taxes	$ 46,718	$ 40,494	$ 50,793

The Company's provision for income taxes differed from the Federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

	1997	1996	1995
		(In thousands)	
Federal income tax at statutory rates	$ 44,700	$ 39,576	$ 44,224
Investment tax credits	(4,436)	(4,476)	(4,442)
Depreciation of flow-through items	519	519	723
Gains on the sale and leaseback of PVNGS Units 1 and 2	(527)	(527)	(527)
State income tax	5,963	5,192	7,146
Gains on sale of utility property	-	-	3,090
Other	499	210	579
Total income taxes	$ 46,718	$ 40,494	$ 50,793

Deferred income taxes result from certain temporary differences between the recognition of income and expense for tax and financial reporting purposes, as described in note 1. The major sources of these differences for which deferred taxes have been provided and the tax effects of each are as follows:

	1997	1996	1995
		(In thousands)	
Deferred fuel costs	$ (9,133)	$ 8,234	$ (3,990)
Depreciation and cost recovery	6,390	18,048	12,730
Loss provision for the M-S-R power purchase contract	-	-	3,497
Contributions in aid of construction	(3,185)	(4,053)	(4,308)
Alternative minimum tax in excess of regular tax	12,482	(1,052)	(26,002)
Net operating losses utilized	-	-	55,217
PVNGS decommissioning	(1,512)	537	(2,321)
Gains on sale of utility property	-	-	(29,868)
Contribution to 401(h) plan	3,181	(510)	(885)
Regulatory liability	-	(6,651)	-
Curtailment gain	-	5,272	-
Transmission project cost	-	4,898	(3,177)
Other	161	2,585	2,926
Net deferred taxes provided	$ 8,384	$ 27,308	$ 3,819

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

	1997	1996
	(In thousands)	
Deferred Tax Assets:		
Alternative minimum tax credit carryforward	$ 55,198	$ 67,681
Nuclear decommissioning	18,226	16,303
Regulatory liabilities	50,689	54,430
Other	46,079	48,944
Total deferred tax assets	$170,192	$187,358
Deferred Tax Liabilities:		
Depreciation	$182,641	$179,430
Investment tax credit	57,823	62,258
Fuel costs	23,905	33,038
Regulatory assets	68,524	69,151
Other	16,475	16,005
Total deferred tax liabilities	349,368	359,882
Accumulated deferred income taxes, net	$179,176	$172,524

The following table reconciles the change in the net accumulated deferred income tax liability to the deferred income tax expense included in the consolidated statement of earnings for the period:

Net change in deferred income tax liability per above table	$ 6,652
Change in tax effects of income tax related regulatory assets and liabilities	(3,114)
Tax effect of excess pension liability	410
Deferred income tax expense for the period	$ 3,948

The Company has no net operating loss carryforwards as of December 31, 1997.

(7) EMPLOYEE AND POST - RETIREMENT BENEFITS

Pension Plan

The Company and its subsidiaries have a pension plan covering substantially all of their employees, including officers. The plan is non-contributory and provides for benefits to be paid to eligible employees at retirement based primarily upon years of service with the Company and the average of their highest annual base salary for three consecutive years. The Company's policy is to fund actuarially-determined contributions. Contributions to the plan reflect benefits attributed to employees' years of service to date and also for services expected to be provided in the future. Plan assets primarily consist of common stock, fixed income securities, cash equivalents and real estate. The components of pension cost (in thousands) are as follows:

	1997	1996	1995
Service cost	$ 6,535	$ 8,540	$ 6,770
Interest cost	19,592	20,546	18,332
Actual return on plan assets	(69,069)	(31,211)	(42,148)
Net amortization and deferral	44,513	9,577	23,295
Net periodic pension cost	1,571	7,452	6,249
Curtailment gain	-	(13,317)	-
Total pension expense (income)	$ 1,571	$ (5,865)	$ 6,249

In December 1996, the Company's Board approved changes to the Company's defined benefit pension plan and implementation of a defined contribution plan no later than January 1, 1998. As a result, the Company recorded a curtailment gain of approximately $13.3 million in the consolidated financial statements for the year ended December 31, 1996.

The following sets forth the plan's funded status and amounts (in thousands) at December 31:

	1997	1996
Vested benefits	$267,021	$233,687
Non-vested benefits	30,658	13,470
Accumulated benefit obligation	297,679	247,157
Effect of future compensation levels	–	11,894
Projected benefit obligation	297,679	259,051
Fair value of plan assets	330,550	273,981
Projected benefit obligation less than plan assets	(32,871)	(14,930)
Unrecognized prior service cost	(146)	(180)
Net unrecognized loss from past experience different from assumed and the effects of changes in assumptions	14,828	(5,814)
Unamortized asset at transition, being amortized through the year 2002	4,650	5,814
Accrued pension asset	$ (13,539)	$ (15,110)

The weighted average discount rate used to measure the projected benefit obligation was 7.75% for 1997 and 1996, and the expected long-term rate of return on plan assets was 8.75% for 1997 and 1996. The rate of increase in future compensation levels based on age-related scales was not applicable for 1997 and 4.1% for 1996.

Other Postretirement Benefits

The Company provides medical and dental benefits to eligible retirees. Currently, retirees are offered the same benefits as active employees after reflecting Medicare coordination. The components of postretirement benefit cost (in thousands) are as follows:

	1997	1996	1995
Service cost	$ 1,300	$ 1,449	$ 1,869
Interest cost	4,452	4,478	4,962
Actual return on plan assets	(6,076)	(1,208)	(2,726)
Transition obligation amortization	1,817	1,817	1,817
Net amortization and deferral	4,192	(159)	2,498
Total postretirement benefit expense	$ 5,685	$ 6,377	$ 8,420

The following sets forth the plan's funded status and amounts (in thousands) at December 31:

	1997	1996
Accumulated benefit obligations for:		
Retirees	$ 26,664	$ 25,237
Fully eligible employees	16,079	15,375
Active employees	16,341	17,787
Accumulated benefit obligation	59,084	58,399
Fair value of plan assets	33,159	20,930
Funded status	(25,925)	(37,469)
Net unrecognized (gain) loss	(4,033)	2,416
Unrecognized transition obligation (being amortized through the year 2012)	27,256	29,074
Accrued postretirement liability	$ (2,702)	$ (5,979)

Plan assets consist primarily of domestic common stock, fixed income securities and cash equivalents.

The weighted average discount rate used to measure the projected benefit obligation was 7.25% and 7.75% for 1997 and 1996, respectively, and the expected long-term rate of return on plan assets was 8.75% for 1997 and 1996. The health care cost trend rate was 8.0% for 1997, 1996 and 1995. The effect of a 1% increase in the health care trend rate assumption would increase the accumulated postretirement benefit obligation as of December 31, 1997 by approximately $10.5 million and the aggregate service and interest cost components of net periodic postretirement benefit cost for 1997 by approximately $1.2 million. The health care cost trend rate was expected to decrease to 5.0% by 2010 and to remain at that level thereafter.

Executive Retirement Program

The Company has an executive retirement program for a group of management employees. The program was intended to attract, motivate and retain key management employees. The Company's projected benefit obligation for this program, as of December 31, 1997, was $19.2 million, of which the accumulated and vested benefit obligation was $19.2 million. As of December 31, 1997, the Company has recognized an additional liability of $2.7 million for the amount of unfunded accumulated benefits in excess of accrued pension costs. The net periodic pension cost for 1997, 1996 and 1995 was $2.2 million, $2.1 million and $2.0 million, respectively. In 1989, the Company established an irrevocable grantor trust in connection with the executive retirement program. Under the terms of the trust, the Company may, but is not obligated to, provide funds to the trust, which was established with an independent trustee, to aid it in meeting its obligations under such program. Marketable securities in the amount of approximately $10.1 million (fair market value of $15.2 million) are presently in trust. No additional funds have been provided to the trust since 1989.

Stock Option Plans

The Company's Performance Stock Plan is a non-qualified stock option plan, covering a group of management employees. Options are granted at the fair market value of the shares on the date of the grant. Options granted through December 31, 1995, vested on June 30, 1996, have an exercise term of up to 10 years. All subsequent awards granted after December 31, 1995, vest three years from the grant date of the awards. The maximum number of options authorized are five million shares through December 31, 2000.

In addition, the Company has a Director Retainer Plan which provides for payment of the Directors' annual retainer in the form of cash, restricted stock or stock options. The number of options granted in 1997 under the Director Retainer Plan was 12,000 shares with an exercise price of $6.625. No options under the Director Retainer Plan were exercised during 1997. The number of option shares outstanding as of December 31, 1997 was 16,000.

The fair value of each option grant is determined on the date of grant using the Black-Scholes option-pricing model with the following average assumptions used for grants in 1995, 1996 and 1997, respectively: dividend yield of 2.7%, 2.4% and 3.0%; expected volatility of 20%, 18% and 20%, risk-free interest rates of 5.5%, 5.59% and 5.69%; and expected lives of four years.

A summary of the status of the Company's stock option plans at December 31, and changes during the years then ended is presented below:

	1997		1996		1995	
FIXED OPTIONS	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	846,787	$18.480	508,986	$17.625	–	–
Granted	312,707	$23.033	390,228	$19.480	508,986	$17.625
Exercised	98,211	$17.625	51,286	$17.625	–	–
Forfeited	13,998	$19.625	1,141	$17.625	–	–
Outstanding at end of year	1,047,285	$19.858	846,787	$18.480	508,986	$17.625
Options exercisable at year-end	362,348		456,559		–	
Weighted-average fair value of options granted during the year	$4.71		$3.56		$3.49	

The following table summarizes information about stock options outstanding at December 31, 1997:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING AT 12/31/97	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICES	NUMBER EXERCISABLE AT 12/31/97	WEIGHTED AVERAGE EXERCISE PRICES
\$ 5.50 - \$ 6.625	16,000	9.75 years	\$ 6.344	4,000	\$ 5.50
\$ 17.625 - \$ 23.6875	1,031,285	8.93 years	\$ 20.06	358,348	\$17.625
\$ 5.50 - \$ 23.6875	1,047,285	8.95 years	\$ 19.858	362,348	\$17.491

Had compensation cost for the Company's performance stock plan been determined consistent with SFAS No. 123, *Accounting for Stock-Based Compensation*, the effect on the Company's pro forma net earnings and pro forma earnings per share would be as follows:

		1997	1996	1995
		(In thousands except per share amounts)		
Net Earnings: *(Available for common)*	As Reported	\$80,409	\$71,994	\$71,848
	Pro Forma	\$80,018	\$70,952	\$71,848
Basic EPS:	As Reported	\$ 1.92	\$ 1.72	\$ 1.72
	Pro Forma	\$ 1.92	\$ 1.70	\$ 1.72
Diluted EPS:	As Reported	\$ 1.91	\$ 1.71	\$ 1.72
	Pro Forma	\$ 1.90	\$ 1.70	\$ 1.72

(8) CONSTRUCTION PROGRAM AND JOINTLY-OWNED PLANTS

It is estimated that the Company's construction expenditures for 1998 will be approximately \$141.3 million, including expenditures on jointly-owned projects. The Company's proportionate share of expenses for the jointly -owned plants is included in operating expenses in the consolidated statements of earnings.

At December 31, 1997, the Company's interests and investments in jointly-owned generating facilities are:

STATION (FUEL TYPE)	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	CONSTRUCTION WORK IN PROGRESS	COMPOSITE INTEREST
	(In thousands)			
San Juan Generating Station (Coal)	\$ 725,308	\$341,237	\$21,679	46.3%
Palo Verde Nuclear Generating Station (Nuclear)*	\$190,649	\$ 40,434	\$16,537	10.2%
Four Corners Power Plant Units 4 and 5 (Coal)	\$ 118,305	\$ 55,703	\$ 3,812	13.0%

* Includes the Company's interest in PVNGS Unit 3, the Company's interest in common facilities for all PVNGS units and the 22% beneficial interests in the PVNGS Units 1 and 2 leases.

San Juan Generating Station

The Company operates and jointly owns SJGS. At December 31, 1997, SJGS Units 1 and 2 are owned on a 50% shared basis with Tucson Electric Power Company, Unit 3 is owned 50% by the Company, 41.8% by Southern California Public Power Authority and 8.2% by Tri-State Generation and Transmission Association, Inc. Unit 4 is owned 38.457% by the Company, 28.8% by M-S-R Public Power Agency, California public power agency ("M-S-R"), 10.04% by the City of Anaheim, California, 8.475% by the City of Farmington, 7.2% by the County of Los Alamos, and 7.028% by Utah Associated Municipal Power Systems.

Palo Verde Nuclear Generating Station

The Company has a 10.2% undivided interest in PVNGS. Commercial operation commenced in 1986 for Unit 1 and Unit 2 and 1988 for Unit 3. In 1985 and 1986, the Company completed sale and leaseback transactions for its undivided interests in Units 1 and 2 and certain related common facilities.

In 1992, the Company purchased approximately 22% of the beneficial interests in the PVNGS Units 1 and 2 leases for approximately $17.5 million, recording $158.3 million as utility plant and $140.8 million as long-term debt. In 1993, such utility plant was written down to $46.7 million in conjunction with an electric retail rate reduction.

The PVNGS participants have insurance for public liability payments resulting from nuclear energy hazards to the full limit of liability under Federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. The maximum assessment per reactor under the retrospective rating program for each nuclear incident occurring at any nuclear power plant in the United States is approximately $79.3 million, subject to an annual limit of $10 million per incident. Based upon the Company's 10.2% interest in the three PVNGS units, the Company's maximum potential assessment per incident for all three units is approximately $24.3 million, with an annual payment limitation of $3 million per incident. The insureds under this liability insurance include the PVNGS participants and "any other person or organization with respect to his legal responsibility for damage caused by the nuclear energy hazard". If the funds provided by this retrospective assessment program prove to be insufficient, Congress could impose revenue raising measures on the nuclear industry to pay claims.

The PVNGS participants maintain "all-risk" (including nuclear hazards) insurance for nuclear property damage to, and decontamination of, property at PVNGS in the aggregate amount of approximately $2.75 billion as of January 1, 1998, a substantial portion of which must be applied to stabilization and decontamination. The Company has also secured insurance against portions of the increased cost of generation or purchased power and business interruption resulting from certain accidental outages of any of the three PVNGS units if the outage exceeds 17 weeks. The Company is a member of two industry mutual insurers. These mutual insurers provide both the "all-risk" and increased cost of generation insurance to the Company. In the event of adverse losses experienced by these insurers, the Company is subject to an assessment. The Company's maximum share of any assessment is approximately $4.3 million per year.

The Company has a program for funding its share of decommissioning costs for PVNGS. Under a portion of this program, the Company makes a series of annual deposits under agreements approved by the NMPUC to an external non-qualified trust which are applied towards an investment in life insurance policies on certain current and former employees. The remaining portion of the nuclear decommissioning funding program is invested in equities in qualified and non-qualified trusts. The results of the 1995 decommissioning cost study indicated that the Company's share of the PVNGS decommissioning costs will be approximately $162.6 million (in 1997 dollars).

Pursuant to NMPUC approval, the Company funded an additional $2.1 million and $12.5 million in 1997 and 1996, respectively, into the qualified and non-qualified trust funds. The estimated market value of the trusts, including the net cash value of the current life insurance policies, at the end of 1997 was approximately $30.9 million.

(9) LONG-TERM POWER CONTRACTS

The Company had two long-term contracts for the purchase of electric power. Under a contract with M-S-R, which expired in early 1995, the Company was obligated to pay certain minimum amounts and a variable component representing the expenses associated with the energy purchased and debt service costs associated with capital improvements. Total payments under this contract amounted to approximately $14 million for 1995.

The Company has a power purchase contract with SPS for up to 200 MW, expiring in May 2011. The Company may reduce its purchases from SPS by 25 MW annually upon three years' notice. The Company provided such notice to reduce the purchase by 25 MW in 1999 and by an additional 25 MW in 2000. Also, the Company has 39 MW of contingent capacity obtained from El Paso Electric Company under a transmission capacity for generation capacity trade arrangement that increases to 70 MW from 1998 through 2003. In addition, the Company is interconnected with various utilities for economy interchanges and mutual assistance in emergencies.

The Company anticipates the need for approximately 100 to 200 MW of additional capacity in the 1998 through 2000 timeframe. To meet this need, in 1996, the Company entered into a long-term power purchase contract with the Cobisa-Person Limited Partnership ("PLP") to purchase approximately 100 MW of unit contingent peaking capacity from a gas turbine generating unit for a period of 20 years, with an option to renew for an additional five years. The gas turbine generating unit will be constructed and operated by the PLP and will be located on the Company's retired Person Generating Station site located in Albuquerque, New Mexico. The site for the generating unit was chosen, in part, to provide needed benefits to the Company's constrained transmission system. In October 1996, the Company filed a request for approval from the NMPUC. The NMPUC issued a final order approving the application in September 1997. The final order also included approval of a stipulated settlement agreement ("Stipulation") which had earlier been entered into among the Company, the PLP and the NMPUC staff to resolve certain issues raised in this proceeding. The Stipulation included, among other things, a provision wherein the Company committed, in cooperation with the NMPUC staff, to the development and evaluation of a request for proposal ("RFP") for purchase of approximately 5 MW of capacity from solar generation resources. The Company would not be obligated to build such a unit or commit to such a power purchase agreement prior to NMPUC approval of a full-recovery mechanism that would not put the Company at a competitive disadvantage.

The NMPUC docketed a new case to follow the progress of the RFP and address the issue of full-cost recovery. The RFP was issued on January 16, 1998. Proposals are due on March 24, 1998. It is expected that contracts with successful bidders will be signed by June 6, 1998 in order to facilitate the NMPUC hearing on full-cost recovery, which has been scheduled for June 15, 1998.

On December 23, 1997, the PLP received FERC approval for "exempt wholesale generator" status with respect to the gas turbine generating unit, as defined in Section 32 of the Public Utility Holding Company Act. Under the power purchase agreement, construction of the gas turbine generating unit is expected to begin in August 1998, with commercial operation and power delivery scheduled in May 1999. The operation date was chosen to satisfy both resource and transmission needs anticipated for the Company's jurisdictional load. However, a reduction in the Company's load forecast for 1999 combined with technical issues concerning one of the candidate gas turbines has lead the Company and PLP to consider a nine to twelve month delay in the operation date.

In addition to the long-term power purchase contract with the PLP, the Company is pursuing other options to ensure its additional capacity needs are met.

(10) LEASE COMMITMENTS

The Company leases Units 1 and 2 of PVNGS, certain transmission facilities, office buildings and other equipment under operating leases. The lease expense for PVNGS is $66.3 million per year over base lease terms expiring in 2015 and 2016. Prior to 1992, the aggregate lease expense for the PVNGS leases was $84.6 million per year over the base lease terms; however, this amount was reduced by the purchase of approximately 22% of the beneficial interests in the PVNGS Units 1 and 2 leases (see note 8). Each PVNGS lease contains renewal and fair market value purchase options at the end of the base lease term. Covenants in the Company's PVNGS Units 1 and 2 lease agreements limit the Company's ability, without consent of the owner participants and bondholders in the lease transactions, (i) to enter into any merger or consolidation, or (ii) except in connection with normal dividend policy, to convey, transfer, lease or dividend more than 5% of its assets in any single transaction or series of related transactions.

Future minimum operating lease payments (in thousands) at December 31, 1997 are:

1998	$ 79,436
1999	79,068
2000	78,711
2001	78,528
2002	78,425
Later years	950,979
Total minimum lease payments	$1,345,147

Operating lease expense, inclusive of PVNGS leases, was approximately $80.8 million in 1997, $80.3 million in 1996 and $80.0 million in 1995. Aggregate minimum payments to be received in future periods under noncancelable subleases are approximately $5.9 million.

(11) ENVIRONMENTAL ISSUES AND RETIRED FOSSIL-FUELED PLANT DECOMMISSIONING COSTS

The Company is committed to complying with all applicable environmental regulations. Environmental issues have presented and will continue to present a challenge to the Company. The Company has evaluated the potential impacts of the following environmental issues and believes, after consideration of established reserves, that the ultimate outcome of these environmental issues will not have a material adverse effect on the Company's financial condition or results of operations.

ELECTRIC OPERATIONS

Santa Fe Generating Station ("Santa Fe Station")

The Company and the New Mexico Environment Department ("NMED") have conducted investigations of the groundwater contamination detected beneath the former Santa Fe Station site to determine the source of the contamination. The Company has been and is continuing to cooperate with the NMED regarding site investigations and remedial planning pursuant to a Settlement Agreement between the Company and the NMED. In June 1996, the Company received a letter from the NMED, indicating that the NMED believes the Company is the source of gasoline contamination in a municipal well supplying the City of Santa Fe and groundwater underlying the Santa Fe Station. Further, the NMED letter stated that the Company was required to proceed with interim remediation of the contamination pursuant to the New Mexico Water Quality Control Commission ("NMWQCC") regulations. In July 1996, the Company filed an appeal with the NMWQCC protesting the determination and directives contained in the NMED's June 1996 letter. Subsequently, negotiation meetings were conducted between the Company and the NMED for a resolution of the groundwater contamination issue.

On October 3, 1996, the Company and the NMED signed an Amendment to the Settlement Agreement concerning the groundwater contamination underlying the site. As part of the Amendment, the Company agreed to spend approximately $1.2 million ("Settlement Amount") for certain costs related to sampling, monitoring, and development and implementation of a remediation plan.

The amended Settlement Agreement does not, however, provide the Company with a full and complete release from potential further liability for remediation of the groundwater contamination. After the Company has expended the Settlement Amount, if the NMED can establish through binding arbitration that the Santa Fe Station is the source of the contamination, the Company could be required to perform further remediation that is determined to be necessary. The Company continues to dispute any contention that the Santa Fe Station is the source of the groundwater contamination and believes that insufficient data exists to identify the sources of groundwater contamination. The Company has completed an aquifer characterization report and a groundwater quality report associated with the 40 day reactivation of the adjacent Santa Fe supply well in July and August of 1996. These reports strongly suggest the groundwater contamination does not originate from the Santa Fe Station site and has been drawn under the site by the pumping of the Santa Fe supply well. In addition, other urban wells in Santa Fe are likely to be vulnerable to contamination from off-site sources.

The Company and the NMED, with the cooperation of the City of Santa Fe, have chosen a remediation plan proposed by a remediation contractor. The City of Santa Fe, the Company and the NMED have entered into a Memorandum of Understanding concerning the chosen remediation plan and the operation of the municipal well adjacent to the Santa Fe Station site in connection with carrying out that plan. Construction of the remediation system under the plan is expected to commence in the second quarter of 1998. The system is expected to be in operation early in the third quarter of 1998.

Person Generating Station ("Person Station")

The Company, in compliance with the NMED's Corrective Action Directive, determined that groundwater contamination exists in the deep and shallow groundwater at the Person Station site. The Company is required to delineate the extent of the contamination and remediate the contaminants in the groundwater at the Person Station site. The extent of the contaminant plume in the deep groundwater was assessed and results were reported to the NMED. The Company currently is involved with the process to renew the Resource Conservation and Recovery Act post-closure care permit for the facility. Remedial actions for the deep groundwater will be incorporated into the new permit. The Company has proposed a monitoring program in conjunction with natural attenuation processes as the most cost effective approach for the deep groundwater remediation. The Company's current estimate to decommission its retired fossil-fueled plants includes approximately $6.3 million in additional expenses to complete the groundwater remediation program at Person Station. As part of the financial assurance requirement of the Person Station Hazardous Waste Permit, the Company established a trust fund. The current value of the trust fund at December 31, 1997, was $7.3 million. The remediation program continues on schedule.

GAS OPERATIONS

Gas Wellhead Pit Remediation

The New Mexico Oil Conservation Commission issued an order, effective on January 14, 1993, that affects the gas gathering facilities located in the San Juan Basin in northwestern New Mexico. The Bureau of Land Management ("BLM") has issued a similar order. The order prohibits the further discharge of fluids associated with the production of natural gas into unlined earthen pits in specified areas (designated as "vulnerable areas") in the San Juan Basin. The order also required the submission of closure plans for the pits where further discharge was prohibited. The Company has complied with the orders and has submitted and received approval for pit closures from the New Mexico Oil Conservation Division ("OCD") and the BLM.

These gas gathering facilities were sold to Williams Gas Processing-Blanco, Inc., a subsidiary of the Williams Field Services Group, Inc., of Tulsa, Oklahoma ("Williams") on June 30, 1995. As a part of the purchase and sale agreement, the Company agreed to cease discharge to unlined earthen pits in designated vulnerable areas and to retain the responsibility for pit closures for a stated period of time and to a stated dollar amount. The Company has assessed the pits in accordance with OCD/BLM directives, and is now in the process of closing pits and remediating them, if necessary, at wellhead locations within the designated vulnerable areas. The Company has submitted a groundwater management plan to the OCD and has received approval of the plan, and is proceeding with delineation of groundwater contamination and, as necessary, cleanup, in accordance with the approved plan. The Company will address soil and groundwater contamination within the dollar and time limitations imposed by the purchase and sale agreement with Williams, and in accordance with the requirements of the OCD.

In March 1995, the Jicarilla Apache Tribe ("Jicarilla") enacted an ordinance directing that unlined surface impoundments located within environmentally sensitive areas be remediated and closed by December 1996, and that all other unlined surface impoundments on Jicarilla lands be remediated and closed by December 1998. In 1995, the Company received a claim for indemnification by Williams, the purchaser of the Company's gas gathering and processing assets, for the environmental work required to comply with the Jicarilla ordinance. The Company submitted a closure/remediation plan to the Jicarillas, which was approved. The Company's remediation work pursuant to the plan commenced in mid-1996, and the costs of remediation are being charged against the $10.6 million indemnification cap contained in the purchase and sale agreement between the Company and Williams. The Company met the requirement for closing and remediating pits within the environmentally sensitive area by December 1996, and anticipates closing and remediating all other pits associated with the gas gathering and processing assets by the December 1998 deadline specified in the ordinance.

(12) ASSET SALES

In 1995, the Company and its subsidiaries sold certain nonstrategic gas assets for approximately $154 million to Williams, recognizing an after-tax gain of $12.8 million. This gain was adjusted to $11.8 million in 1996 due to an accrual for additional gas environmental costs. Under the NMPUC order approving the sale, the Company is required to share approximately $35 million from the sale with customers, which is being credited to the customer's bills over five years. After completion of the fifth year, the amount of gain will be recalculated to include actual expenses specified in the agreement, subject to NMPUC review. As of December 31, 1997, the Company has a remaining balance of $11.9 million for future years credit to its customers. However, as a result of the increase in estimated sales expense, the Company proposed in another NMPUC case to retain $7.2 million of the $11.9 million until all actual expenses have been accumulated. The NMPUC has not issued an order on the Company's proposal. In addition, the Company, in 1995, sold its water division to the City of Santa Fe for $51.2 million (exclusive of current assets netted against current liabilities), recognizing an after-tax gain of $6.4 million. The Company, through its Energy Services Business Unit, has a contract with the City of Santa Fe to operate the Santa Fe water systems through the year 2001.

(13) SEGMENT INFORMATION

The Company primarily operates in three business segments, as indicated below. A description of each of the Company's three segments and their products, services and markets served is included in Part I of the Annual Report on Form 10-K. Corporate administrative expenses are allocated to segments based upon the nature of the expense.

Summarized financial information by business segment for 1997, 1996 and 1995 is as follows:

	ELECTRIC*	GAS	ENERGY SERVICES**	OTHER	TOTAL
			(In thousands)		
1997:					
Operating revenues	$ 722,438	$294,769	$118,060	$ –	$1,135,267
Operating expenses excluding income taxes	576,521	263,738	132,629	–	972,888
Pre-tax operating income (loss)	145,917	31,031	(14,569)	–	162,379
Operating income tax (benefit)	36,446	7,587	(5,732)	33	38,334
Operating income (loss)	$ 109,471	$ 23,444	$ (8,837)	$ (33)	$ 124,045
Depreciation and amortization expense	$ 68,089	$ 14,587	$ 26	$ –	$ 82,702
Construction expenditures	$ 96,963	$ 31,408	$ –	$ –	$ 128,371
Identifiable assets:					
Net utility plant	$1,276,927	$296,223	$ –	$ –	$1,573,150
Other	509,007	183,097	40,479	7,999	740,582
Total assets	$1,785,934	$479,320	$ 40,479	$ 7,999	$2,313,732
1996:					
Operating revenues	$ 645,639	$227,301	$ 10,446	$ –	$ 883,386
Operating expenses excluding income taxes	509,804	191,922	16,246	–	717,972
Pre-tax operating income (loss)	135,835	35,379	(5,800)	–	165,414
Operating income tax (benefit)	32,422	8,927	(2,296)	342	39,395
Operating income (loss)	$ 103,413	$ 26,452	$ (3,504)	$ (342)	$ 126,019
Depreciation and amortization expense	$ 64,817	$ 13,122	$ 177	$ –	$ 78,116
Construction expenditures	$ 76,572	$ 26,497	$ 18	$ –	$ 103,087
Identifiable assets:					
Net utility plant	$1,270,141	$281,348	$ 1,204	$ –	$1,552,693
Other	449,478	202,725	13,618	11,800	677,621
Total assets	$1,719,619	$484,073	$ 14,822	$11,800	$2,230,314
1995:					
Operating revenues	$ 584,284	$217,985	–	$ 6,196	$ 808,465
Operating expenses excluding income taxes	470,824	190,128	–	3,931	664,883
Pre-tax operating income	113,460	27,857	–	2,265	143,582
Operating income tax	24,884	4,313	–	997	30,194
Operating income	$ 88,576	$ 23,544	–	$ 1,268	$ 113,388
Depreciation and amortization expense	$ 63,047	$ 17,248	–	$ 570	$ 80,865
Construction expenditures	$ 76,610	$ 26,315	–	$ 4,741	$ 107,666
Identifiable assets:					
Net utility plant	$1,298,103	$276,218	–	$ 113	$1,574,434
Other	327,547	125,387	–	8,301	461,235
Total assets	$1,625,650	$401,605	–	$ 8,414	$2,035,669

* Includes the resources excluded from NMPUC retail rates regulation.

** Energy Services began operations in 1996.

On June 30, 1995, the Company sold substantially all of the gas gathering and processing assets of the Company and its gas subsidiaries and on July 3, 1995, the Company sold its water division (see note 12).

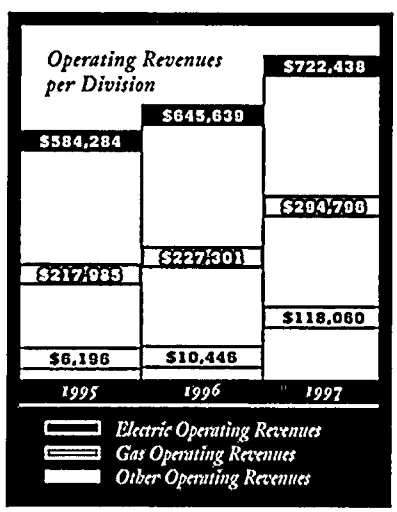
QUARTERLY OPERATING RESULTS

The unaudited operating results by quarters for 1997 and 1996 are as follows:

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
	(In thousands except per share amounts)			
1997:				
Operating Revenues	$298,822	$238,742	$285,971	$311,732
Operating Income	$ 36,693	$ 25,994	$ 34,885	$ 26,473
Net Earnings	$ 24,896	$ 15,567	$ 24,319	$ 16,213
Net Earnings per Share (basic)	$ 0.59	$ 0.37	$ 0.58	$ 0.38
Net Earnings per share (diluted)	$ 0.59	$ 0.37	$ 0.57	$ 0.38
1996:				
Operating Revenues	$241,904	$197,597	$210,757	$233,128
Operating Income	$ 38,475	$ 25,346	$ 32,412	$ 29,786
Net Earnings (1)	$ 26,448	$ 13,542	$ 19,940	$ 12,650
Net Earnings per Share (basic) (1)	$ 0.63	$ 0.32	$ 0.47	$ 0.30
Net Earnings per Share (diluted) (1)	$ 0.62	$ 0.32	$ 0.47	$ 0.30

In the opinion of management of the Company, all adjustments (consisting of normal recurring accruals) necessary for a fair statement of the results of operations for such periods have been included.

(1) During the quarter ended December 31, 1996, the Company made a provision for loss of $10.0 million, net of tax ($.24 per common share), as a result of the gas rate order, pending the outcome of the appeal. In addition, the Company recorded an after-tax curtailment gain of $8.0 million ($.19 per common share) related to the change of the Company's defined benefit pension plan.



GLOSSARY

AG	New Mexico Attorney General
BHP	BHP Minerals International, Inc.
BLM	Bureau of Land Management
COA	City of Albuquerque
EIP	Eastern Interconnection Project
El Paso	El Paso Electric Company
EPNG	El Paso Natural Gas Company
FASB	Financial Accounting Standards Board
Farmington	City of Farmington, New Mexico
FERC	Federal Energy Regulatory Commission
Four Corners	Four Corners Power Plant
FPPCAC	Fuel and Purchased Power Cost Adjustment Clause
KWh	Kilowatt Hour
LOBs	Lease Obligation Bonds
Los Alamos	The County of Los Alamos, New Mexico
M-S-R	M-S-R Public Power Agency, a California public power agency
NMED	New Mexico Environment Department
NMPUC	New Mexico Public Utility Commission
OCD	New Mexico Oil Conservation Division
PGAC	PNMGS' Purchased Gas Adjustment Clause
PNMGS	Public Service Company of New Mexico Gas Services, a division of the Company
PRC	Public Regulation Commission
PVNGS	Palo Verde Nuclear Generating Station
SDG&E	San Diego Gas and Electric Company
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SJCC	San Juan Coal Company
SJGS	San Juan Generating Station
SPS	Southwestern Public Service Company
SUNs	Senior Unsecured Notes
UAMPS	Utah Associated Municipal Power Systems
Williams	Williams Gas Processing-Blanco, Inc., a subsidiary of the Williams Field Services Group, Inc., of Tulsa, Oklahoma

COMMON STOCK PRICES AND DIVIDENDS DECLARED

(In dollars)

	1997			1996		
QUARTER	DIVIDEND	HIGH	LOW	DIVIDEND	HIGH	LOW
1	$0.17	20 1/2	17 1/4	$0.12	18 3/4	17 3/8
2	$0.17	18 5/8	15 3/4	$0.12	20 1/2	17 1/4
3	$0.17	19 9/16	17 3/4	$0.12	20 3/8	19
4	$0.17	23 15/16	18 7/8	$0.12	19 7/8	18 1/8

CORPORATE HEADQUARTERS

Public Service Company of New Mexico
Alvarado Square, Albuquerque, NM 87158
(505) 241-2700

ANNUAL MEETING

The 1998 annual meeting of shareholders will be held on Tuesday, April 28, at the UNM Continuing Education Conference Center, located at 1634 University Boulevard NE, Albuquerque, NM. The meeting will begin at 9:30 a.m. (MDT).

TRANSFER AGENT AND REGISTRAR

PNM Shareholder Records Department, Alvarado Square - 1104, Albuquerque, NM 87158 Telephone: (800) 545-4425; Fax: (505) 241-4311 E-Mail: yjohnson@mail.pnm.com

INVESTOR INFORMATION AND SHAREHOLDER RECORDS INQUIRIES

Investor information is available 24 hours a day, seven days a week by calling PNM's shareholder information line. This automated system features earnings and dividend information, news releases, financial statements and a daily stock quote. Call (800) 840-0PNM.

Other questions concerning stock ownership may be directed to PNM's Shareholder Records Department. Call 1-800-545-4425 or write to the above address.

SECURITIES ANALYST INQUIRIES

Securities analysts, portfolio managers and representatives of financial institutions seeking information about PNM should contact Barbara Barsky, Vice President, Strategy, Analysis and Investor Relations at the corporate headquarters address, or call (505) 241-2662. E-Mail: bbarsky@mail.pnm.com

PNM ON THE INTERNET

PNM's home page on the World Wide Web contains background information on the company, news releases, financial information, and an electronic version of our annual report. Specific information of interest to investors can be found at www.pnm.com

COMMON STOCK LISTING

PNM's common stock is listed under the symbol PNM and primarily traded on the New York Stock Exchange. As of December 31, 1997, there were 17,634 common shareholders of record.

REQUESTS FOR ANNUAL REPORTS OR FORM 10-K

To obtain an additional copy of this annual report or a copy of the annual Form 10-K filed with the Securities and Exchange Commission, call 800-545-4425, or write to Barbara Barsky at the corporate headquarters address.

PUBLIC POLICY ISSUES

PNM encourages its shareholders to take an active interest in the legislative and public policy issues that affect the company and the utility industry. For more information, contact PNM's Investor Relations Department at 1-800-545-4425.

PNM DIRECT

The following investor services are available through PNM's direct stock purchase and dividend reinvestment plan:

Direct purchase of PNM stock
PNM offers a direct stock purchase plan to all interested participants. Shares can be purchased (or sold) at nominal commissions.

Automatic cash contributions
Through PNM Direct participants can make regular cash contributions to purchase additional shares of PNM common stock by having funds automatically withdrawn from their bank accounts.

Direct deposit of dividends
Your PNM quarterly dividends can be deposited automatically into your personal checking or savings account.

Other features and services
- Acceptance of PNM stock certificates for safekeeping
- Minimum $50 investment; $60,000 maximum per year

Call or write Shareholder Records for a prospectus on this popular program.

ARD OF DIRECTORS OFFICERS OF THE COMPAN

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-NOTICE-

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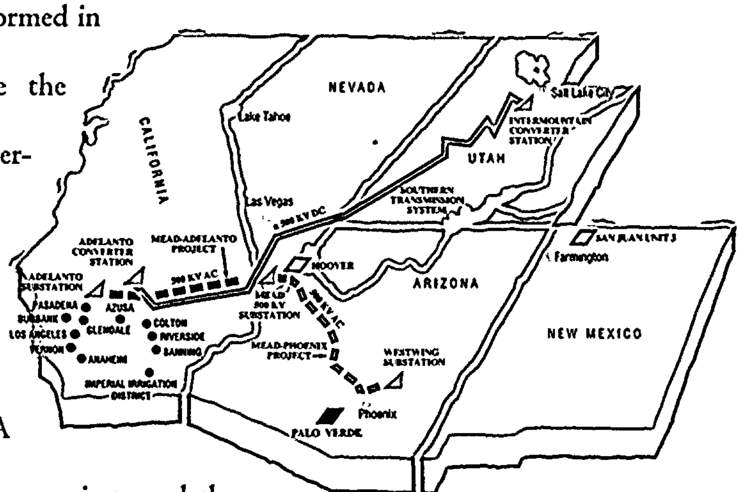
The Southern California Public Power Authority (SCPPA) is a joint powers authority consisting of 10 municipal utilities and one irrigation district, who deliver electricity to 2 million customers over an area of 7,000 square miles, with a total population of 4.8 million.

The members are the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon, and the Imperial Irrigation District.

SCPPA MEMBERS

- City of Anaheim
- City of Azusa
- City of Banning
- City of Burbank
- City of Colton
- City of Glendale
- Imperial Irrigation District
- Los Angeles Department of Water And Power
- City of Pasadena
- City of Riverside
- City of Vernon

SCPPA was formed in 1980 to finance the acquisition of generation and transmission resources for it's members. Currently, SCPPA has three generation projects and three transmission projects, bringing power from Arizona, New Mexico, Utah, and Nevada.



- Southern Transmission System
- Mead-Phoenix Transmission Project
- Mead-Adelanto Transmission Project
- Palo Verde Nuclear Generating Station
- Hoover Uprating Project
- San Juan Generating Station
- Member Agencies

The projects were financed through the issuance of tax-exempt bonds, backed by the combined credit of the SCPPA members participating in each project. As of June 30, 1997, SCPPA had issued $8.45 billion in bonds, including refunding bonds, of which $3.16 billion in principal was outstanding.

SCPPA's role has evolved over the years to include advocacy at the state and national levels, and cooperative efforts to reduce member costs and improve efficiency.

Bernard V. Palk
President

Cooperation among SCPPA members reached new levels this year, and paid high dividends. Facing the enormous challenges of industry deregulation, we realized that common problems could have common solutions, and that by presenting a unified position, we could best influence the course of events to protect our customer/owners.

SCPPA became the local forum for discussion, and the conduit for information to and from Sacramento. SCPPA Directors were heavily involved in shaping the legislation which will change the way we do business in California, and we are represented on the Boards of both the Independent System Operator and the Power Exchange.

We are working together to reduce debt service costs and operating costs on our SCPPA generating projects, and are working individually to reduce local operating costs and to improve customer service.

The individual SCPPA members will decide if and when open access is in the best interests of our individual utilities and customers, but we will continue to search for areas where cooperation and joint action can benefit us all.

This year proved the power of cooperation. Next year holds new challenges, and SCPPA will provide the mechanism to address many of them cooperatively.

Bernard V. Palk

BERNARD V. PALK
President

Daniel W. Waters
Executive Director

Restructuring dominated the California electric utility industry this year, and it certainly dominated my schedule. Along with many of the SCPPA Directors, I was heavily involved in the debate leading up to the enactment of AB 1890 in September 1996. SCPPA and its members continued to be very active in the creation of the Power Exchange and the Independent System Operator. Protecting our member utilities and their customers has been our prime goal, and we feel proud of our success. Public power will not be harmed by this very political process which was driven by the large industrial customers of the California investor-owned utilities.

Throughout the restructuring process, SCPPA worked closely with the California Municipal Utilities Association (CMUA) and the Northern California Power Agency (NCPA). The successful teamwork on restructuring has led to cooperative efforts in other areas. Nine SCPPA members, eight NCPA members, and the Sacramento Municipal Utility District are working together to develop a Public Power Restructuring Education Program to help educate their customers about California's emerging electric market.

In addition, five SCPPA members and seven NCPA members are cooperating on the development of new Customer Information Systems. We will be watching for other areas where North-South cooperation will yield common benefits.

SCPPA completed refundings for the Palo Verde Project and the Southern Transmission Project during this fiscal year, lowering costs for

SCPPA Directors

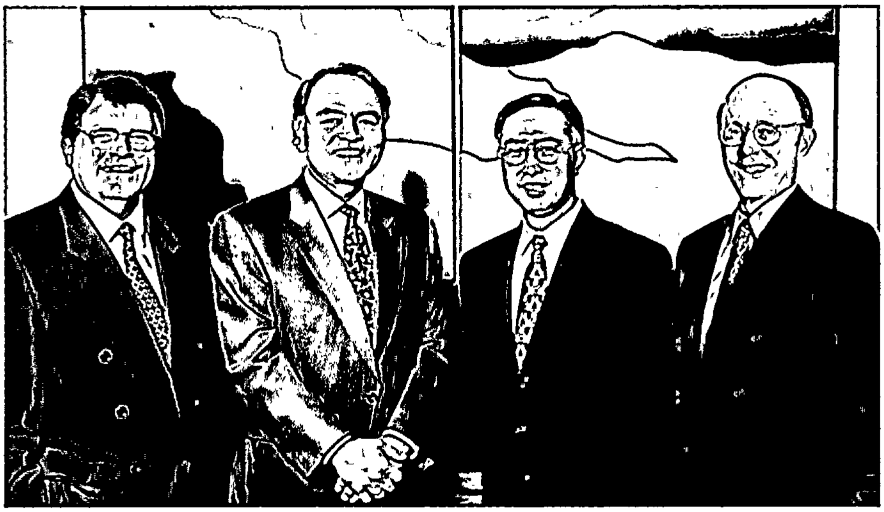
Left to Right:

Daniel W. Waters
Executive Director

Bernard V. Palk
President

Joseph F. Hsu
Vice President

Eldon A. Cotton
Secretary



both projects. At year's end, we were working toward a major restructuring of all the Palo Verde fixed-rate debt, with the goal of lowering the project cost to market value by 2004.

This was an exciting, challenging year. Cooperation among SCPPA members, and with our public power cousins in the North, has helped us shape the immediate future. SCPPA will continue to serve as the hub and catalyst for the joint actions which will help our members to meet the even greater challenges to come.

DANIEL W. WATERS
Executive Director

When SCPPA was formed in 1980, many of its members were effectively "land-locked", completely dependent on Southern California Edison for their generation and transmission requirements. Membership in SCPPA allowed them to become generation and transmission owners. This made their power costs lower and more predictable, gave them more independence and local control, and gave them a voice in regional planning and development.

In the 1980's and early 1990's, environmental constraints, uncertain price and availability of oil and natural gas, and continuing load growth led to investment in nuclear and coal plants by most California utilities. Diversity of fuel type and firm transmission access were thought to be the route to stable rates in the long term. Conventional wisdom also said that spreading the cost out over the entire life of the resource was the most fair to our customers who paid the bills.

In recent years, natural gas has been abundantly available and relatively inexpensive. New technology and this low fuel cost make it possible to generate electricity at a much lower cost than our older power plants. The potential for these lower costs is driving the deregulation of our industry.

Beginning in 1998, California will experience radical change. The investor-owned utilities will divest a significant portion of their fossil-fueled generation, sell all their generation into and supply all their needs from a Power Exchange, and turn their transmission over to an Independent System Operator. They will give residential and small commercial customers a 10% rate decrease, through the sale of billions of dollars

City of Anaheim

Edward K. Aghjayan
Innovation has defined the Anaheim Public Utilities since its inception in 1885, and the utility continues its record of innovation by preparing for the restructured California electric industry. Anaheim Public Utilities' residential rates are 28% lower than the neighboring competitors', and the last three commercial/industrial rate changes have been decreases. In addition, Anaheim Public Utilities has entered into a joint venture which will allow Anaheim to become the first city in the nation with a publicly-owned, privately-run fiber-optic network serving the city.

Customers served	105,743
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	670,471
Purchased	2,240,871
Total	2,911,342
Transmission (in miles)	1,426
Total Revenues (000s)	$244,195
Operating Costs (000s)	$214,323

worth of "rate reduction bonds". Perhaps most importantly, they will lose their service area monopoly, and customers will be free to choose any power supplier.

SCPPA members, as consumer-owned utilities, are not mandated to follow suit, but there will be great political pressure to lower rates and grant customers the right to choose their electricity supplier. SCPPA members are taking action on many fronts to make their rates competitive by the turn of the century, when the full force of competition is expected to hit.

The customers of California's consumer-owned utilities already enjoy lower average retail rates than customers of the neighboring investor-owned utilities, in addition to the benefits of local control, local employment, and contributions to their cities' general funds.

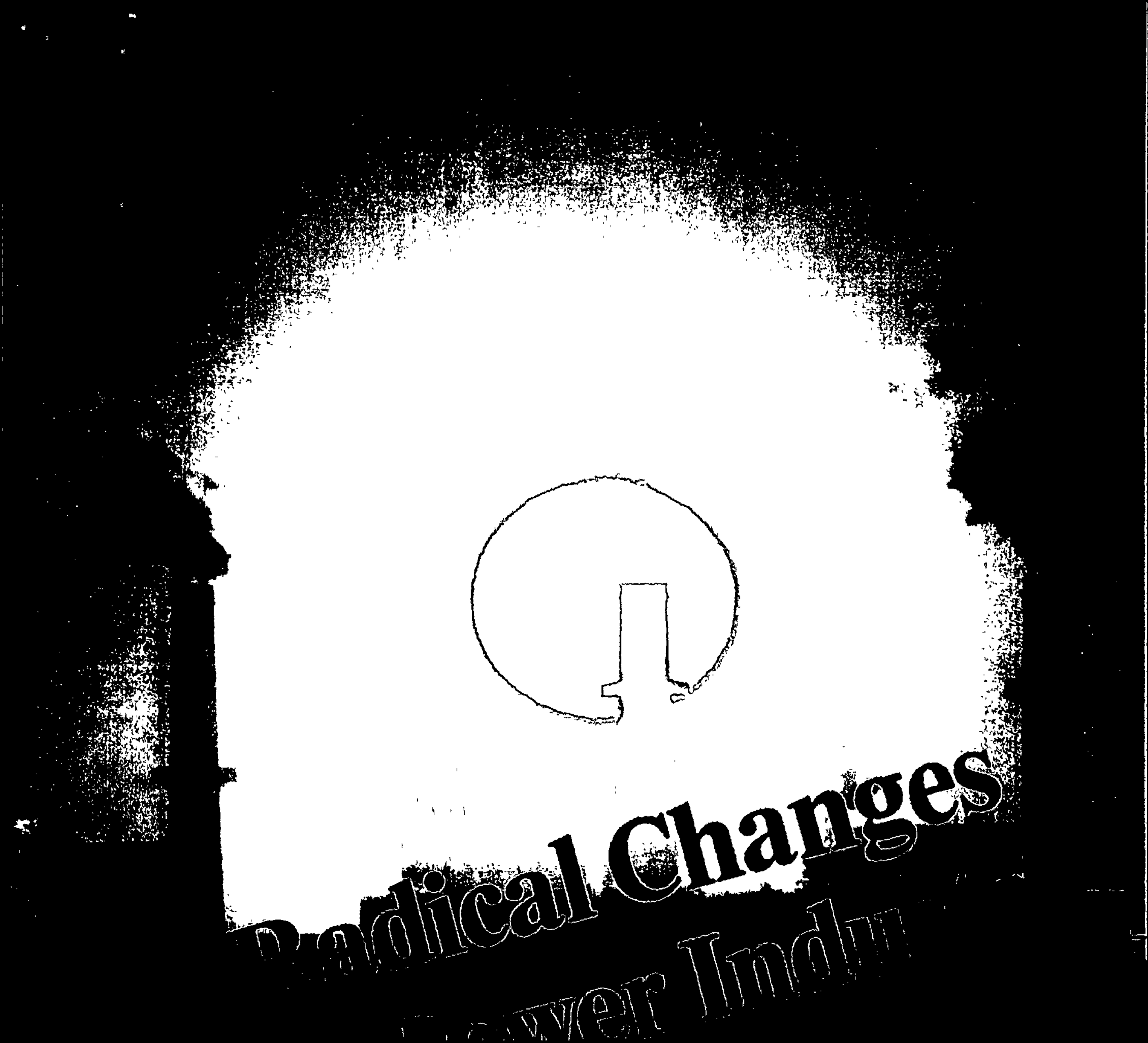
The electric utility industry is evolving. SCPPA and its members are also evolving. Starting as a tool for joint financing, SCPPA has become a catalyst and a vehicle for cooperative long-range planning, problem solving, and political advocacy. Based on a firm belief in the value of public power, SCPPA will continue to evolve in response to its members' needs.

City of Azusa

Joseph F. Hsu
The city's electric utility was established in 1898, and for most of its history Azusa purchased electricity wholesale from Southern California Edison. Since the mid-1980s, through successful litigation against Edison on transmission access, Azusa began to obtain short- and long-term contracts with other utilities, as well as from SCPPA, by participating in Palo Verde Nuclear Generating Station, Hoover Hydroelectric Plant, and San Juan Generating Station Unit #3. By having the ability to diversify its power supply operations, Azusa has maintained its retail rates at the 1983 level. These competitive rates will help the city make a less stressful transition toward the deregulated market environment.

Customers served	14,576
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	0
Purchased	403,169
Sales	
Retail	210,760
Wholesale	178,956
Total Revenues (000s)	$23,786*
Operating Costs (000s)	$24,109*

*Unaudited


Radical Changes

As of October 31, 1997

SCPPA BONDS	Outstanding Principal (000s)	Effective Interest Rate(s)	Average Life (yrs)	Final Maturity	Bond Ratings: Moody's Investor Service	Bond Ratings: Standard & Poor's
Hoover Uprating Project	$ 30,490	6.2%	13.2	Oct 2017	Aa3	AA-
Southern Transmission System	$ 1,166,240	4.3% – 7.2%	21.4	July 2023		
Senior Lien Bonds					Aa3	A+
Subordinate Lien Bonds[1]					Aaa/VMIG1	AAA/A-1+
Palo Verde Project[2]	$ 974,495	4.4% – 7.7%	4.36	July 2017		
Senior Lien Bonds					A2	AA-
Subordinate Lien Bonds					Aaa/VMIG1	AAA/A-1+
Multiple Project Revenue Bonds[3]						
Mead-Adelanto	$ 106,700	7.1%	11.1	July 2013	A3	A
Mead-Phoenix	$ 38,800	7.1%	11.1	July 2013	A3	A
Multiple Project	$ 259,100	7.1%	17.0	July 2020	A3	A
Mead-Adelanto Refunding[4]	$ 173,955	5.3%	18.8	July 2015	Aaa	AAA
Mead-Phoenix Refunding[4]	$ 51,835	5.3%	18.8	July 2015	Aaa	AAA
San Juan Unit 3[5]	$ 231,340	5.6%	14.2	Jan 2020	Aaa	AAA

[1] *Insured: 1991 Subordinate Variable Rate Bonds (AMBAC); 1996 Subordinate Series A Bonds (MBIA); 1996 Subordinate Variable Rate Series B Bonds (FSA).*
[2] *Insured: 1992 Senior Lien Bonds (AMBAC); 1993 Subordinate Bonds (FGIC); 1996 Subordinate Series A (AMBAC); 1996 Subordinate Variable Rate Series B and C Bonds (AMBAC); 1997 Subordinate Series A and B Bonds (FSA).*
[3] *Uncommitted bond proceeds secured by a guaranteed rate investment contract.*
[4] *Insured: 1994 Series A Bonds (AMBAC).*
[5] *Insured: 1993 Series A Bonds (MBIA).*

Palo Verde Operations – This was a year of new records at Palo Verde.

– 29.8 million MWH's produced – a new site record

– 39-day refueling outage for Unit 1 – a new site record

– 37.5-day refueling outage for Unit 3 – another new site record

Unit 2 ended the year having been operational every day of the year, on its way to a new record of 490 days continuous operation. This was the ninth longest uninterrupted run ever recorded by a U.S. nuclear plant.

City of Banning

Paul Toor

Established in 1913, the Banning electrical system now serves an area of approximately 21 square miles. The city owns a portion of San Juan Unit 3 and a portion of Mead-Adelanto and Mead-Phoenix transmission lines. The service is provided to Banning customers through the City owned distribution system. With a proven record of reliability, the City is committed to continue to provide quality service to both present and future customers while positioning itself for effective delivery of services in a competitive deregulated environment.

Customers served	9,349
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	0
Purchased	120,475
Total	120,475
Transmission (in miles)	122
Total Revenues (000s)	$13,009
Operating Costs (000s)	$12,920

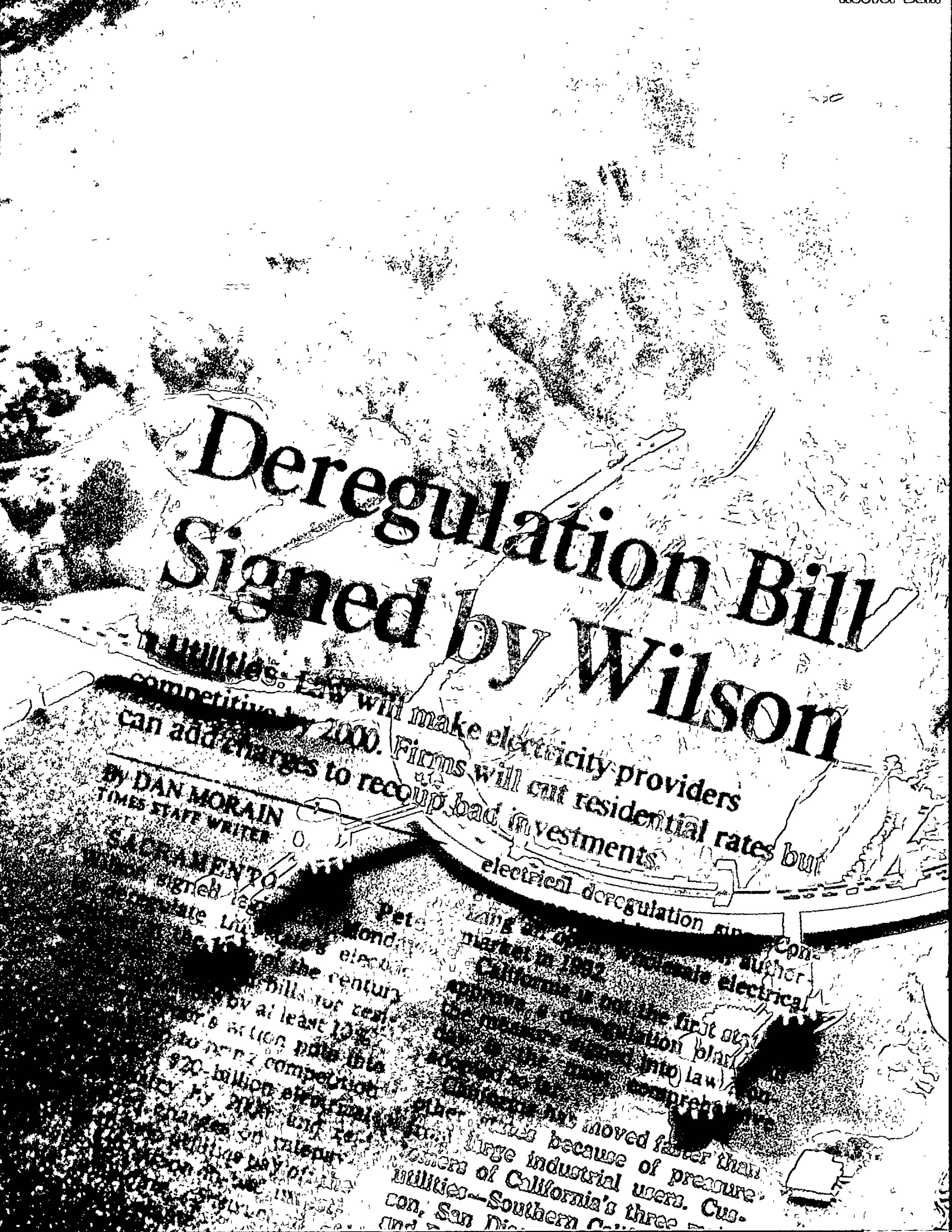
PRODUCTION COST

(Operation and Maintenance plus Nuclear Fuel)

Calendar Year	Cents per kWh
1993	2.02
1994	1.93
1995	1.61
1996	1.45
1997	1.35 (target)

1996-97 OPERATIONS

	Generation (Millions of MWHs)	Capacity Utilization (%)
Unit 1	9.3	86.5
Unit 2	11.0	102.5
Unit 3	9.5	88.1
Aggregate	29.8	92.4
Industry average		70.3


Deregulation Bill
Signed by Wilson
will make electricity providers
Firms will cut residential rates but
can add charges to recoup bad investments
BY DAN MORAIN
TIMES STAFF WRITER
electrical deregulation
because of pressure
large industrial users. Cus-
utilities—Southern California's three

City of Burbank

Ronald V. Stassi Burbank's Public Service Department began serving both water and electric customers in 1913, and installed on-site generation in response to a surge in industrial and residential growth in the 1940s and 1950s. Today the city receives power from three SCPPA projects, as well as firm and interruptible supplies from other utilities and government agencies, and continues to operate its own local power plant.

Customers served	51,189
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	101,000
Purchased	961,000
Total	1,062,000
Transmission (in miles)	398
Total Revenues (000s)	$93,851
Operating Costs (000s)	$90,983

These records are the measurable results of the reengineering of work processes and organization begun by the Operating Agent (Arizona Public Service) in 1993. Improvements in teamwork and morale, and reduced production cost are further evidence of effective management.

San Juan Unit 3 Operations – Unit 3 at the San Juan Generating Station in New Mexico performed well this year, as it has each year since SCPPA purchased a 41.8% share in 1993. Its availability factor was 96.7%, and the five SCPPA participants took nearly 1.7 million MWH's, the highest yet.

The Limestone Conversion Project is well under way, and running under budget. When complete, the 3-year project will improve the removal of sulfur dioxide from the flue gasses, and save SCPPA $3 million per year in operating and maintenance costs.

Interim Invoicing Agreements continue to encourage high capacity factors and lower per unit coal costs, and negotiations are proceeding on a long-term coal supply contract. Both the Operating Agent (Public Service Company of New Mexico) and the coal company realize that an economic fuel supply is vital to the competitive future of both the plant and the coal mine.

City of Colton

Thomas K. Clarke The Colton municipal electric utility was established in 1895, eight years after city incorporation. Since 1986, the electric utility has changed from being solely dependent on Southern California Edison for its purchased power to being actively engaged in purchasing power from several different sources, achieving significant cost savings in the process.

Customers served	15,800
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	0
Purchased	212,300
Total	212,300
Transmission (in miles)	8.3
Total Revenues (000s)	$23,981
Operating Costs (000s)	$23,693

Mead-Phoenix/Mead-Adelanto Transmission Projects – Nine SCPPA members own roughly one-fifth of Mead-Phoenix and one-third of Mead-Adelanto through SCPPA. The two 500-kV AC transmission lines carry power between the Phoenix area, the

... sounding warning

TIMES STAFF WRITER

SACRAMENTO—

... probably the most important bill from Edison in the last decade, if not the last few decades," said Robert Foster, the Southern California ...

Las Vegas area, and Southern California. Both lines successfully completed their first year of operation.

City of Glendale

Bernard V. Palk

Incorporated in 1906, Glendale purchased its electric utility in 1909, obtaining power from outside suppliers. It received its first power from Hoover Dam in 1937 and inaugurated the first unit of its own steam generating plant in 1941. Now called the Grayson Power Plant, this facility today has eight generating units. Glendale continues to purchase 85 percent of its power from outside sources.

Customers served	82,810
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	144,876
Purchased	962,718
Total	1,107,594
Transmission (in miles)	72
Total Revenues (000s)	$122,098
Operating Costs (000s)	$96,923

Hoover Uprating Project – The Uprating Project, which increased the rated capacity at Hoover Power Plant by 35 percent, continues to be an economical, renewable resource for nine SCPPA members, six of which financed their participation through SCPPA. SCPPA is participating in efforts to identify and mitigate effects on endangered species in the lower Colorado River area, and is closely monitoring proposals regarding the sale of the Federal Power Marketing Administrations.

Southern Transmission System (STS) – The STS is a 488-mile long ± 500-kV DC transmission line and associated converter stations which delivers power from the Intermountain Converter Station in Utah to the Adelanto Converter Station in Southern California. In its usual "ho-hum" fashion, the STS delivered nearly 14 million MWH in fiscal year 1996-97, with 99.62% availability.

Los Angeles Department of Water and Power

Eldon A. Cotton

In 1916, the City of Los Angeles began distributing electric power purchased from the Pasadena Municipal Power Plant, and the following year inaugurated its first generating capacity at San Francisquito Power Plant No. 1. In 1922 the city purchased the remaining distribution system of Southern California Edison Company within the city limits. It is now the largest municipally owned electric utility in the nation and is undergoing a major business restructuring process to prepare for upcoming deregulation.

Customers served	1,358,000
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	10,626,000
Purchased	15,401,000
Total	26,027,000
Transmission (in miles)	3,743
Total Revenues (000s)	$2,017,100
Operating Costs (000s)	$1,447,000

Adelanto Converter Station

Imperial Irrigation District

Kenneth S. Noller

IID entered the power industry in 1936 and today serves a peak load of 640 MW with 790 MW of generating resources. Among IID-owned resources are 24 MW of low head hydro units along the All American Canal, 307 MW of gas-fired steam and combined cycle units, and 162 MW of peaking gas turbines. In addition to IID's share of SCPPA resources comprising 104 MW at San Juan and 14 MW at Palo Verde, IID has 179 MW of other resources under long-term purchase contracts.

Customers served	88,533
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	806,068
Purchased	1,855,115
Total	2,661,183
Transmission Facilities (in miles)	1,648
Total Revenues (000s)	$199,766
Operating Costs (000s)	$201,388

Throughout fiscal year 1996-97, SCPPA closely monitored the legislative activities at the state and federal levels and played an active role in educating elected officials and staff on the unique services, needs, and concerns of public power systems. As federal lawmakers and regulators continue to advance proposals to restructure the electric utility industry, these activities will be increasingly important.

SCPPA emerged as a serious player in the debate leading up to California's restructuring legislation, and the final bill bears the marks of SCPPA's influence.

Restructuring was also one of the hot issues on Capitol Hill in 1997, and promises to be a major legislative issue during 1998. Members of Congress heard from hundreds of witnesses, including SCPPA, who testified before the Senate Energy and Natural Resources Committee on several issues key to public power's ability to compete.

As Congress debates the merits of retail competition, one of the most hotly contested issues is the private-use limitation on tax-exempt bonds. Throughout the 105th Congress, investor-owned utilities actively lobbied Congress, charging that tax exempt bonds and the tax exemption of public power systems give public power an unfair advantage in a competitive market. SCPPA and other public power supporters are working to counter these charges by aggressively educating Members of Congress and Administration officials on the rationale and need to protect the status of tax exempt bonds for municipal utility systems in a competitive environment.

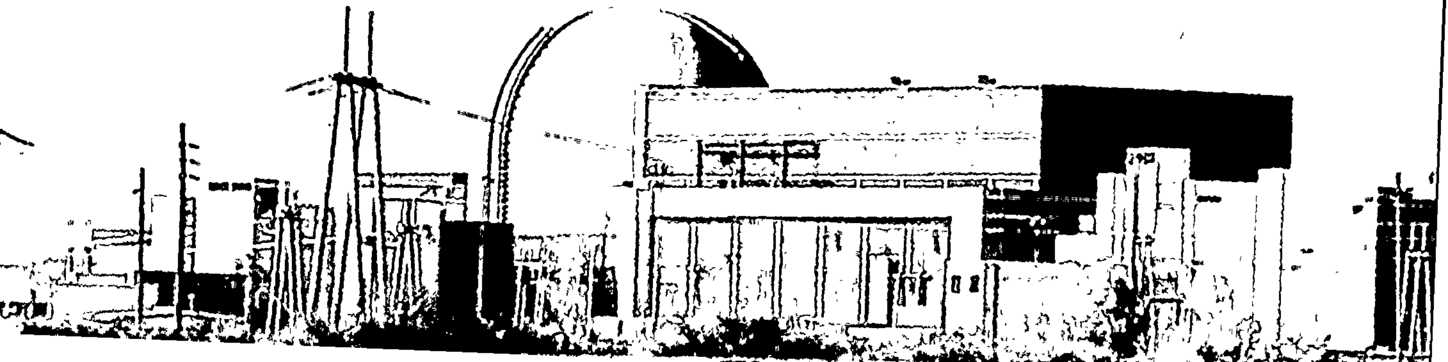
City of Pasadena

Rufus Hightower

Established in 1906, the city built its first electric generating steam plant in 1907 and took over operation of its municipal street lighting from Edison Electric. In 1909, Pasadena began the extension of its operations to commercial and residential customers that resulted in the replacement of all Edison electric service in the city by 1920. In 1996-97, Pasadena purchased approximately 85 percent of its power needs.

Customers served	57,978
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	185,085
Purchased	106,627
Total	1,254,712
Transmission Facilities (in miles)	.57
Total Revenues (000s)	$111,969
Operating Costs (000s)	$95,654

Palo Verde Nuclear Generating Station



City of Riverside

Bill D. Carnahan Riverside Public Utilities is positioning itself to offer competitive rates in the new deregulated environment. Power and transmission costs constitute the bulk of charges passed on to our customers through rates. Cost reduction and restructuring efforts at SCPPA have had significant impact on Riverside Public Utilities' efforts in meeting our lower operating cost targets. Additional efforts, especially at Palo Verde Nuclear Generating Station, will be required for Riverside to compete in future years.

Customers served	89,562
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	227,176
Purchased	1,496,364
Total	1,723,540
Transmission (in miles)	2,085
Total Revenues (000s)	$183,117
Operating Costs (000s)	$167,327

Other issues of interest to SCPPA and its members include:

Nuclear Waste Disposal – SCPPA and its allies in Washington will continue to work with government leaders to develop an effective and safe nuclear waste storage program.

Sale of the Power Marketing Administrations (PMA's) – In contrast to prior years, sale of the federal PMA's was not a legislative priority in 1997. However, the issues of PMA rates and federal ownership may well become part of the restructuring debate in 1998.

Telecommunications – As part of its legislative strategy, SCPPA is continuing its dialogue with officials of the Federal Communications Commission to ensure that implementation of the 1996 Telecommunications Act preserves the right of municipal utilities to compete in the telecommunications arena.

In addition to legislative issue areas, SCPPA hosted for the third straight year a group of congressional staff on a fact-finding tour of SCPPA facilities. The tour was designed to increase the staff members' knowledge and understanding of how the legislative debate on restructuring, taxes and other energy issues affect SCPPA and its members.

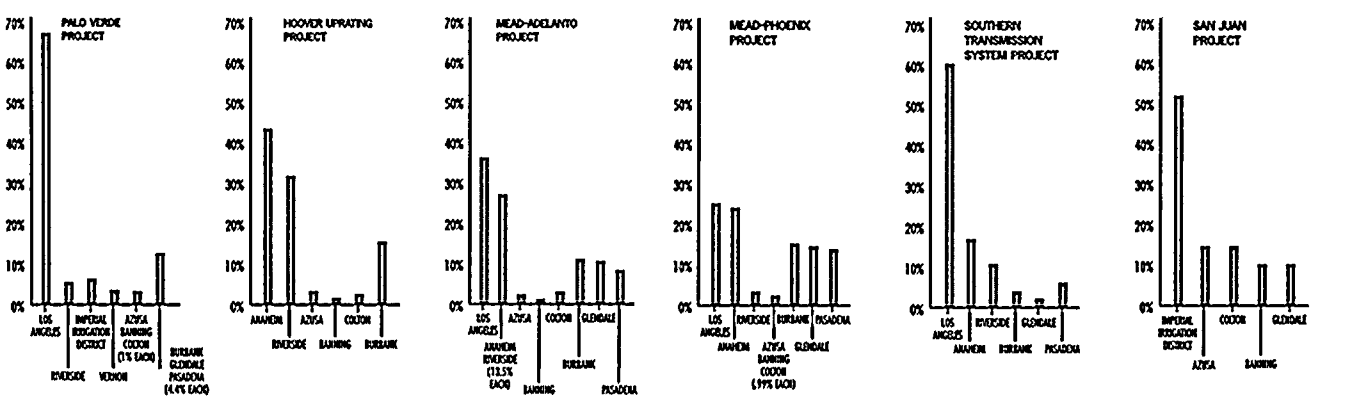
City of Vernon

Kenneth J. De Dario Vernon's Light and Power Department began serving industrial customers in 1933, with completion of its diesel generating plant. In addition to its own power from diesel units plus recently installed gas turbines, Vernon now receives power from Palo Verde, Hoover, and various utilities, including APS, CDWR, SRP, BPA and Edison.

Customers served	2,045
Power Generated and Purchased (in Megawatt-Hours)	
Self-generated	5,345
Purchased	1,112,655
Total	1,118,000
Transmission (in miles)	2.4
Total Revenues (000s)	$53,774*
Operating Costs (000s)	$39,074*

*Unaudited

PERCENTAGE OF SCPPA MEMBER PARTICIPATION IN SCPPA'S INTEREST



REPORT OF INDEPENDENT ACCOUNTANTS

September 11, 1997

To the Board of Directors of the Southern California Public Power Authority

In our opinion, the accompanying combined balance sheet and the related combined statements of operations and of cash flows after the restatements described in Note 9, present fairly, in all material respects, the financial position of the Southern California Public Power Authority (Authority) at June 30, 1997 and 1996, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

In our opinion, the accompanying separate balance sheets and the related separate statements of cash flows of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project, Mead-Phoenix Project, Mead-Adelanto Project, Multiple Project Fund and San Juan Project and the separate statements of operations of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project, Mead-Phoenix Project, Mead-Adelanto Project and San Juan Project, after the restatements described in Note 9, present fairly, in all material respects, the financial position of each of the Projects at June 30, 1997 and 1996, and their cash flows, and the results of operations of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project, Mead-Phoenix Project, Mead-Adelanto Project and San Juan Project for the years then ended in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits.

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

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental financial information, as listed on the accompanying index, is presented for purposes of additional analysis and is not a required part of the basic financial statements. This information is the responsibility of the Authority's management. Such information has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Price Waterhouse LLP

Price Waterhouse LLP
Los Angeles, California

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED BALANCE SHEET
(In thousands)

	June 30, 1997								
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Mead-Phoenix Project*	*Mead-Adelanto Project*	*Multiple Project Fund*	*San Juan Project*	*Projects' Stabilization and Other Funds*	*Total*
ASSETS									
Utility plant:									
Production	$ 615,214						$ 183,208		$ 798,422
Transmission	14,153	$ 674,606		$ 51,189	$ 170,895				910,843
General	2,656	18,893		2,627	335		7,865		32,376
	632,023	693,499		53,816	171,230		191,073		1,741,641
Less - Accumulated depreciation	279,927	213,844		2,202	5,828		43,112		544,913
	352,096	479,655		51,614	165,402		147,961		1,196,728
Construction work in progress	10,026						210		10,236
Nuclear fuel, at amortized cost	13,514								13,514
Net utility plant	375,636	479,655		51,614	165,402		148,171		1,220,478
Special funds:									
Available for sale at fair value (Note 2):									
Decommissioning fund	43,943								43,943
Investments	155,763	138,550	$ 4,906	18,586	58,380	$ 252,779	37,431	$ 4,442	670,837
Escrow account		15,484							15,484
Advance to Intermountain Power Agency		11,550							11,550
Advances for capacity and energy, net			24,526						24,526
Interest receivable	1,946	583	6	690	2,057	9,288	134	7	14,711
Cash and cash equivalents	27,396	32,442	2,503	2,761	4,229	73	7,503	10,463	87,370
	229,048	198,609	31,941	22,037	64,666	262,140	45,068	14,912	868,421
Accounts receivable	2,878			2,122	5,386	(7,345)			3,041
Materials and supplies	7,511						3,494		11,005
Costs recoverable from (in excess of) future billings to participants	230,497	241,326	(7,042)	4,163	14,544		33,706		517,194
Unrealized loss (gain) on investments in funds available for sale	733	(1,116)	74		1		3	115	(190)
Unamortized debt expenses, less accumulated amortization of $118,434	182,491	197,675	3,058	9,368	26,639		2,805		422,036
	$ 1,028,794	$ 1,116,149	$ 28,031	$ 89,304	$ 276,638	$ 254,795	$ 233,247	$ 15,027	$ 3,041,985
LIABILITIES									
Long-term debt	$ 965,151	$ 1,065,877	$ 26,999	$ 86,570	$ 268,456	$ 243,466	$ 216,496		$ 2,873,015
Deferred credits		112				3,073			3,185
Current liabilities:									
Long-term debt due within one year	28,570	21,360	515				6,275		56,720
Accrued interest	22,660	24,394	402	2,588	7,884	8,256	5,873		72,057
Accounts payable and accrued expenses	12,413	4,406	115	146	298		4,603	$ 15,027	37,008
Total current liabilities	63,643	50,160	1,032	2,734	8,182	8,256	16,751	15,027	165,785
Commitments and contingencies									
	$ 1,028,794	$ 1,116,149	$ 28,031	$ 89,304	$ 276,638	$ 254,795	$ 233,247	$ 15,027	$ 3,041,985

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED BALANCE SHEET
(In thousands)

	June 30, 1996							
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Mead-Phoenix Project*	*Mead-Adelanto Project*	*Multiple Project Fund*	*San Juan Project*	*Total*
ASSETS								
Utility plant:								
Production	$ 613,608						$ 183,309	$ 796,917
Transmission	14,146	$ 674,606		$ 48,307	$ 171,068			908,127
General	2,569	18,893		1,971	164		8,613	32,210
	630,323	693,499		50,278	171,232		191,922	1,737,254
Less - Accumulated depreciation	250,021	194,127		846	1,255		36,622	482,871
	380,302	499,372		49,432	169,977		155,300	1,254,383
Construction work in progress	9,503			3,116			3,501	16,120
Nuclear fuel, at amortized cost	13,225							13,225
Net utility plant	403,030	499,372		52,548	169,977		158,801	1,283,728
Special funds:								
Available for sale at fair value (Note 2):								
Decommissioning fund	33,474							33,474
Investments	115,746	102,842	$ 9,628	21,591	62,562	$ 250,888	34,170	597,427
Escrow account - Crossover series		343,898						343,898
Advance to Intermountain Power Agency		19,550						19,550
Advances for capacity and energy, net			25,183					25,183
Interest receivable	1,512	2,169	6	841	2,285	9,220	67	16,100
Cash and cash equivalents	67,879	90,324	1,997	1,548	4,504		7,546	173,798
	218,611	558,783	36,814	23,980	69,351	260,108	41,783	1,209,430
Accounts receivable	738	2,687	19	1,750	4,741	(6,402)	945	4,478
Materials and supplies	9,240						3,569	12,809
Costs recoverable from (in excess of) future billings to participants	217,926	215,490	(7,526)	1,394	4,383		31,780	463,447
Unrealized loss on investments in funds available for sale	456	2,865	3	9	28		4	3,365
Prepaid expenses				26	66			92
Unamortized debt expenses, less accumulated amortization of $139,796	191,712	163,079	3,307	9,888	28,123		3,090	399,199
	$ 1,041,713	$ 1,442,276	$ 32,617	$ 89,595	$ 276,669	$ 253,706	$ 239,972	$ 3,376,548
LIABILITIES								
Long-term debt	$ 981,155	$ 1,045,292	$ 30,981	$ 86,417	$ 268,005	$ 242,786	$ 222,444	$ 2,877,080
Subordinate Refunding Crossover Series		347,388						347,388
Deferred credits						2,664		2,664
Current liabilities:								
Long-term debt due within one year	25,690	10,845	1,085				6,035	43,655
Accrued interest	24,535	38,436	489	2,588	7,884	8,256	5,994	88,182
Accounts payable and accrued expenses	10,333	315	62	590	780		5,499	17,579
Total current liabilities	60,558	49,596	1,636	3,178	8,664	8,256	17,528	149,416
Commitments and contingencies								
	$ 1,041,713	$ 1,442,276	$ 32,617	$ 89,595	$ 276,669	$ 253,706	$ 239,972	$ 3,376,548

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF OPERATIONS

(In thousands)

	Year Ended June 30, 1997						
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	San Juan Project	Total
Operating revenues:							
Sales of electric energy	$ 119,507		$ 2,521			$ 58,017	$ 180,045
Sales of transmission services		$ 85,054		$ 3,282	$ 8,194		96,530
Reimbursement to participants		(8,000)					(8,000)
Total operating revenues	119,507	77,054	2,521	3,282	8,194	58,017	268,575
Operating expenses:							
Amortization of nuclear fuel	7,755						7,755
Other operations	21,411	9,997	2,082	507	875	257	35,129
Maintenance	5,818	4,460		73	207	37,181	47,739
Depreciation	18,371	19,717		1,356	4,573	9,139	53,156
Decommissioning	11,593					3,113	14,706
Total operating expenses	64,948	34,174	2,082	1,936	5,655	49,690	158,485
Operating income	54,559	42,880	439	1,346	2,539	8,327	110,090
Investment income	11,423	17,150	140	1,482	4,313	2,241	36,749
Income before debt expense	65,982	60,030	579	2,828	6,852	10,568	146,839
Debt expense	78,553	85,866	1,063	5,597	17,013	12,494	200,586
Costs recoverable from future billings to participants	($ 12,571)	($ 25,836)	($ 484)	($ 2,769)	($ 10,161)	($ 1,926)	($ 53,747)

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF OPERATIONS
(In thousands)

	Year Ended June 30, 1996						
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Mead-Phoenix Project*	*Mead-Adelanto Project*	*San Juan Project*	*Total*
Operating revenues:							
Sales of electric energy	$ 135,464		$ 3,349			$ 50,117	$ 188,930
Sales of transmission services		$ 85,297		$ 226	$ 172		85,695
Total operating revenues	135,464	85,297	3,349	226	172	50,117	274,625
Operating expenses:							
Amortization of nuclear fuel	7,949						7,949
Other operations	25,815	10,192	2,200	213	145	314	38,879
Maintenance	6,317	5,236		13	27	35,760	47,353
Depreciation	18,425	20,329		342	1,132	9,095	49,323
Decommissioning	12,497					3,113	15,610
Total operating expenses	71,003	35,757	2,200	568	1,304	48,282	159,114
Operating income (loss)	64,461	49,540	1,149	(342)	(1,132)	1,835	115,511
Investment income	10,886	28,993	874	410	1,174	2,062	44,399
Income before debt expense	75,347	78,533	2,023	68	42	3,897	159,910
Debt expense	82,777	102,710	1,370	1,462	4,425	12,614	205,358
Costs (recoverable from) in excess of future billings to participants	($ 7,430)	($ 24,177)	$ 653	($ 1,394)	($ 4,383)	($ 8,717)	($ 45,448)

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF CASH FLOWS
(In thousands)

	June 30, 1997								
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Mead-Phoenix Project*	*Mead-Adelanto Project*	*Multiple Project Fund*	*San Juan Project*	*Projects' Stabilization and Other Funds*	*Total*
Cash flows from operating activities:									
Operating income	$ 54,559	$ 42,880	$ 439	$ 1,346	$ 2,539		$ 8,327		$ 110,090
Adjustments to reconcile operating income to net cash provided by operating activities -									
Depreciation	18,371	19,717		1,356	4,573		9,139		53,156
Decommissioning	11,593						3,113		14,706
Advances for capacity and energy, net			1,710						1,710
Amortization of nuclear fuel	7,755								7,755
Reimbursement to participants		8,000							8,000
Changes in assets and liabilities:									
Accounts receivable	(2,140)	2,687	19	(372)	(646)		945		493
Materials and supplies	1,729						75		1,804
Other assets	25			26	66				117
Accounts payable and accrued expenses	2,080	4,203	53	(444)	(482)		(896)		4,514
Net cash provided by operating activities	93,972	77,487	2,221	1,912	6,050		20,703		202,345
Cash flows from noncapital financing activities:									
Advances from participants								$ 16,835	16,835
Participant withdrawals								(2,149)	(2,149)
Net cash provided by noncapital financing activities	–	–	–	–	–		–	14,686	14,686
Cash flows from capital and related financing activities:									
Payments for construction of facilities	(10,325)			(422)			(1,623)		(12,370)
Payments of interest on long-term debt	(51,127)	(74,876)	(1,784)	(4,924)	(15,077)	($ 16,512)	(12,002)		(176,302)
Proceeds from sale of bonds	153,034	199,739							352,773
Transfers from escrow account - Crossover series		343,898							343,898
Payment for defeasance/redemption of revenue bonds	(157,015)	(561,565)	(3,637)						(722,217)
Repayment of principal on long-term debt	(25,690)	(10,845)	(1,085)				(6,035)		(43,655)
Decommissioning fund	(10,469)								(10,469)
Payment for bond issue costs	(3,558)	(2,250)							(5,808)
Net cash used for capital and related financing activities	(105,150)	(105,899)	(6,506)	(5,346)	(15,077)	(16,512)	(19,660)		(274,150)
Cash flows from investing activities:									
Interest received on investments	10,989	17,741	140	1,633	4,541	18,475	2,174	219	55,912
Purchases of investments	(111,714)	(161,198)	(10,663)	(939)	(9,276)	(2,030)	(25,553)	(6,767)	(328,140)
Proceeds from sale/maturity of investments	71,420	113,987	15,314	3,953	13,487	140	22,293	2,325	242,919
Net cash provided by (used for) investing activities	(29,305)	(29,470)	4,791	4,647	8,752	16,585	(1,086)	(4,223)	(29,309)
Net increase (decrease) in cash and cash equivalents	(40,483)	(57,882)	506	1,213	(275)	73	(43)	10,463	(86,428)
Cash and cash equivalents at beginning of year	67,879	90,324	1,997	1,548	4,504	–	7,546	–	173,798
Cash and cash equivalents at end of year	$ 27,396	$ 32,442	$ 2,503	$ 2,761	$ 4,229	$ 73	$ 7,503	$ 10,463	$ 87,370

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended June 30, 1996							
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Mead-Phoenix Project*	*Mead-Adelanto Project*	*Multiple Project Fund*	*San Juan Project*	*Total*
Cash flows from operating activities:								
Operating income (loss)	$ 64,461	$ 49,540	$ 1,149	($ 342)	($ 1,132)		$ 1,835	$ 115,511
Adjustments to reconcile operating income (loss) to net cash provided by operating activities -								
Depreciation	18,425	20,329		342	1,132		9,095	49,323
Decommissioning	12,497						3,113	15,610
Amortization of nuclear fuel	7,949							7,949
Advances for capacity and energy, net			1,784					1,784
Write-off of construction work in progress costs		1,313						1,313
Changes in assets and liabilities:								
Accounts receivable	174	(218)	(19)	213	(72)		946	1,024
Materials and supplies	378						110	488
Other assets	55			1,977	3,467		56	5,555
Accounts payable and accrued expenses	(6,437)	(1,943)	(7)	556	745		1,482	(5,604)
Net cash provided by operating activities	97,502	69,021	2,907	2,746	4,140		16,637	192,953
Cash flows from noncapital financing activities	–	–	–	–	–		–	–
Cash flows from capital and related financing activities:								
Payments for construction of facilities	(10,892)			(13,208)	(15,652)		(1,938)	(41,690)
Payments of interest on long-term debt	(64,499)	(88,370)	(1,979)	(1,295)	(3,944)	($ 16,512)	(11,988)	(188,587)
Proceeds from sale of bonds	229,483							229,483
Payment for defeasance of revenue bonds	(233,632)							(233,632)
Decommissioning fund	(8,971)							(8,971)
Repayment of principal on long-term debt	(23,855)	(14,325)	(610)					(38,790)
Payment for bond issue costs	(4,832)							(4,832)
Net cash used for capital and related financing activities	(117,198)	(102,695)	(2,589)	(14,503)	(19,596)	(16,512)	(13,926)	(287,019)
Cash flows from investing activities:								
Interest received on investments	10,597	28,631	894	815	1,865	18,380	2,064	63,246
Purchases of investments	(154,685)	(154,904)	(22,665)	(3,264)	(9,184)	(1,868)	(14,370)	(360,940)
Proceeds from sale/maturity of investments	182,309	195,593	20,705	14,474	23,000		8,867	444,948
Net cash provided by (used for) investing activities	38,221	69,320	(1,066)	12,025	15,681	16,512	(3,439)	147,254
Net increase (decrease) in cash and cash equivalents	18,525	35,646	(748)	268	225	–	(728)	53,188
Cash and cash equivalents at beginning of year	49,354	54,678	2,745	1,280	4,279	–	8,274	120,610
Cash and cash equivalents at end of year	$ 67,879	$ 90,324	$ 1,997	$ 1,548	$ 4,504	$ –	$ 7,546	$ 173,798

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

Note 1 — Organization And Purpose:

Southern California Public Power Authority (Authority), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participant membership consists of ten Southern California cities and one public district of the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation and transmission of electric energy for sale to its participants. The Joint Powers Agreement has a term of fifty years.

The members have the following participation percentages in the Authority's interest in the projects at June 30, 1997 and 1996:

Participants	Palo Verde	Southern Transmission System	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan
City of Los Angeles	67.0%	59.5%		24.8%	35.7%	
City of Anaheim		17.6	42.6%	24.2	13.5	
City of Riverside	5.4	10.2	31.9	4.0	13.5	
Imperial Irrigation District	6.5					51.0%
City of Vernon	4.9					
City of Azusa	1.0		4.2	1.0	2.2	14.7
City of Banning	1.0		2.1	1.0	1.3	9.8
City of Colton	1.0		3.2	1.0	2.6	14.7
City of Burbank	4.4	4.5	16.0	15.4	11.5	
City of Glendale	4.4	2.3		14.8	11.1	9.8
City of Pasadena	4.4	5.9		13.8	8.6	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Mead-Phoenix participation reflects three ownership components (see below).

The members participate in the Projects' Stabilization Fund by making deposits to the fund at their discretion.

The members do not currently participate in the Multiple Project Fund as it was established to provide funding for unspecified future projects.

Palo Verde Project – The Authority, pursuant to an assignment agreement dated as of August 14, 1981 with the Salt River Project (Salt River), purchased a 5.91% interest in the Palo Verde Nuclear Generating Station (PVNGS), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the Palo Verde Project).

As of July 1, 1981, ten participants had entered into power sales contracts with the Authority to purchase the Authority's share of PVNGS capacity and energy. Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Southern Transmission System Project – The Authority, pursuant to an agreement dated as of May 1, 1983 with the Intermountain Power Agency (IPA), has made payments-in-aid of construction to IPA to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS), which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. The Authority entered into an agreement also dated as of May 1, 1983 with six of its participants pursuant to which each member assigned its entitlement to capacity of STS to the Authority in return for the Authority's agreement to make payments-in-aid of construction to IPA. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles (LADWP), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project (IPP).

Hoover Uprating Project – The Authority and six participants entered into an agreement dated as of March 1, 1986, pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation (USBR) on behalf of such participants. The USBR has declared that the Project is substantially complete. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project (HU). All seventeen "uprated" generators of the HU have commenced commercial operations.

Mead-Phoenix Project – The Authority entered into an agreement dated as of December 17, 1991 to acquire an interest in the Mead-Phoenix Project (MP), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component and a 22.41% interest in the Mead-Marketplace project component. The Authority has entered into transmission service contracts for the entire capability of its interest with nine members of the Authority on a "take or pay" basis. In addition, the Authority has administrative responsibility for accounting for the separate ownership interest in the project by Western Area Power Administration (WAPA), who is providing separate funding ($73,011,000 and $72,874,000 at June 30, 1997 and 1996, respectively) for its interest. Commercial operations of MP commenced in April 1996. Funding was provided by a transfer of funds from the Multiple Project Fund (Note 4).

Mead-Adelanto Project – The Authority entered into an agreement dated as of December 17, 1991 to acquire a 67.92% interest in the Mead-Adelanto Project (MA), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. The Authority has entered into transmission service contracts for the entire capability of its interest with nine members of the Authority on a "take or pay" basis. In addition, the Authority has administrative responsibility for accounting for the separate ownership interest in the project by WAPA, who is providing separate funding ($17,088,000 at June 30, 1997 and 1996) for its interest. Funding was provided by a transfer of funds from the Multiple Project Fund (Note 4). Commercial operations commenced in April 1996. LADWP serves as both construction manager and operations manager.

Multiple Project Fund – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more then unspecified projects for the generation or transmission of electric energy.

In August 1992, the Authority's Board of Directors approved a resolution authorizing the use of certain proceeds of Multiple Project Revenue Bonds to finance the Authority's ownership interests in the Mead-Phoenix and Mead-Adelanto projects. Transfers made from the Multiple Project Fund are sufficient to provide for the Authority's share of the estimated costs of acquisition and construction of these two projects, including reimbursement of planning, development and other related costs.

San Juan Project – Effective July 1, 1993, the Authority purchased a 41.80% interest in Unit 3, a 488 megawatt unit and related common facilities, of the San Juan Generating Station (SJGS) from Century Power Corporation. Unit 3 is one unit of a four-unit coal-fired power generating station in New Mexico. The Authority allocated the $193 million purchase price to the estimated fair value of the utility plant ($190 million) and to materials and supplies ($3 million). The purchase has been financed through the issuance of approximately $237 million (par value) of San Juan Project Revenue Bonds. The Authority has entered into power sales contracts for the entire capability of its interest with five members of the Authority on a "take or pay" basis.

Projects' Stabilization Fund – In fiscal 1997 the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Participants have discretion over the use of their deposits to pay costs and expenses of Authority related projects. This fund is not a project-related fund, therefore, it is not governed by any project Indenture of Trust.

Note 2 — Summary Of Significant Accounting Policies:

The financial statements of the Authority are presented in conformity with generally accepted accounting principles, and substantially in conformity with accounting principles prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission. The Authority is not subject to regulation by either of these regulatory bodies.

The Authority complies with all applicable pronouncements of the Governmental Accounting Standards Board (GASB). In accordance with GASB Statement No. 20, "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting," the Authority also complies with authoritative pronouncements applicable to nongovernmental entities (i.e., Financial Accounting Standards Board statements) which do not conflict with GASB pronouncements.

The financial statements represent the Authority's share in each jointly-owned project. The Authority's share of direct expenses of jointly-owned projects are included in the corresponding operating expense of the statement of operations. Each owner of the jointly-owned projects is required to provide their own financing.

Utility Plant – The Authority's share of all expenditures, including general administrative and other overhead expenses, payments-in-aid of construction, interest net of related investment income, deferred cost amortization and the fair value of test power generated and delivered to the participants are capitalized as utility plant construction work in progress until a facility commences commercial operation.

The Authority's share of construction and betterment costs associated with PVNGS is included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service life of thirty-five years. Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the Authority is charged one mill per kilowatt-hour, by the federal government, on its share of electricity produced by PVNGS, and such funds will eventually be utilized by the federal government to provide for PVNGS' nuclear waste disposal. The Authority records this charge as a current year expense.

The Authority's share of construction and betterment costs associated with STS, MP, MA and SJGS are included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service lives, principally thirty-five years for STS, MA and MP and twenty-one years for SJGS.

Interest costs incurred by the MP and MA projects through the date commercial operations commenced (April 1996) are capitalized as utility plant. Interest costs capitalized in fiscal 1996 were $11,827,000 for the MA project and $3,881,000 for the MP project.

Advances for Capacity and Energy – Advance payments to USBR for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by the principal portion of the credits on billings to the Authority for energy and capacity.

Nuclear Decommissioning – Decommissioning of PVNGS is projected to commence subsequent to the year 2022. Based upon an updated study performed by an independent engineering firm, the Authority's share of the estimated decommissioning costs is $85.5 million in 1995 dollars ($390 million in 2022 dollars assuming a 6% estimated annual inflation rate). The Authority is providing for its share of the estimated future decommissioning costs over the remaining life of the nuclear power plant (25 to 27 years) through annual charges to expense which amounted to $11.6 million and $12.5 million in fiscal 1997 and 1996, respectively. The decommissioning liability is included as a component of accumulated depreciation and was $99.7 million and $88.1 million at June 30, 1997 and 1996, respectively.

A Decommissioning Fund has been established and partially funded at $43.9 million at June 30, 1997. The Decommissioning Fund earned interest income of $2,690,000 and $1,341,000 during fiscal 1997 and 1996, respectively.

Demolition and Site Reclamation – Demolition and site reclamation of SJGS, which involves restoring the site to a "green" condition which existed prior to SJGS construction, is projected to commence subsequent to the year 2014. Based upon a study performed by an independent engineering firm, the Authority's share of the estimated demolition and site reclamation costs is $18.7 million in 1992 dollars ($65.3 million in 2014 dollars using a 6% estimated annual inflation rate). The Authority is providing for its share of the estimated future demolition costs over the remaining life of the power plant (18 years) through annual charges to expense of $3.1 million. The demolition liability is included as a component of accumulated depreciation and was $12.5 million and $9.3 million at June 30, 1997 and 1996, respectively.

As of June 30, 1997, the Authority has not billed participants for the cost of demolition nor has it established a demolition fund.

Unamortized Debt Expenses – Unamortized debt issue costs, including the loss on refundings, are being amortized over the shorter of the terms of the respective issues or the remaining terms of the bonds refunded, and are reported net of accumulated amortization. Total deferred loss on refundings, net of accumulated amortization, was $395,095,000 and $378,070,000 at June 30, 1997 and 1996, respectively.

Investments – Investments include United States Government and governmental agency securities and repurchase agreements which are collateralized by such securities. Additionally, the Mead-Phoenix Project, the Mead-Adelanto Project and the Multiple Project Fund's investments are comprised of an investment agreement with a financial institution earning a guaranteed rate of return. The Southern Transmission System Project has debt service reserve funds associated with the 1991 and 1992 Subordinate Refunding Series Bonds invested with a financial institution under a specific investment agreement allowed under the Bond Indenture earning a guaranteed rate of return.

Investments available for sale are carried at aggregate fair value and changes in unrealized net gains or losses are recorded separately. Investments are reduced to estimated net realizable value when necessary for declines in value considered to be other than temporary. Gains and losses realized on the sale of investments are generally determined using the specific identification method. As discussed in Note 3, all of the investments are restricted as to their use.

Cash and Cash Equivalents – Cash and cash equivalents include cash and all investments with original maturities less than 90 days.

Revenues – Revenues consist of billings to participants for the sales of electric energy and of transmission service in accordance with the participation agreements. Generally, revenues are fixed at a level to recover all operating and debt service costs over the commercial life of the property (see Note 6).

Debt Expense – Debt expense includes interest on debt and the amortization of bond discounts, debt issuance expense and loss on refunding costs.

Arbitrage Rebate – A rebate payable to the Internal Revenue Service (IRS) results from the investment of the proceeds from the Multiple Project Revenue Bond offering in a taxable financial instrument that yields a higher rate of interest income than the cost of the associated funds. The excess of interest income over costs is payable to the IRS within five years of the date of the bond offering and each consecutive five years thereafter. The Authority made a payment of $3.8 million at the end of the initial rebate period during fiscal year 1995. The next rebate payment to the IRS is due in fiscal year 2000. As of June 30, 1997 and 1996, the Authority had no liability relating to Arbitrage Rebate.

Reclassifications – Certain reclassifications have been made in the fiscal year 1996 financial statements to conform to the fiscal year 1997 presentation.

Use of Estimates – The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Note 3 — Special Funds:

The Bond Indentures for the six projects and the Multiple Project Fund require the following special funds to be established to account for the Authority's receipts and disbursements. The moneys and investments held in these funds are restricted in use to the purposes stipulated in the Bond Indentures. A summary of these funds follows:

Fund	Purpose
Construction	To disburse funds for the acquisition and construction of the Project.
Debt Service	To pay interest and principal related to the Revenue Bonds.
Revenue	To initially receive all revenues and disburse them to other funds.
Operating	To pay operating expenses.
Reserve and Contingency	To pay capital improvements and make up deficiencies in other funds.
General Reserve	To make up any deficiencies in other funds.
Advance Payments	To disburse funds for the cost of acquisition of capacity.
Proceeds Account	To initially receive the proceeds of the sale of the Multiple Project Revenue Bonds.
Earnings Account	To receive investment earnings on the Multiple Project Revenue Bonds.
Revolving Fund	To pay the Authority's operating expenses.
Decommissioning Fund	To accumulate funds related to the future decommissioning of PVNGS.
Issue Fund	To initially receive pledged revenues associated with the applicable subordinated refunding series' Indenture of Trust and pay the related interest and principal.
Escrow account - Subordinate Refunding Crossover Series	To initially receive pledged revenues associated with Component 3 of the 1993 Subordinate Refunding Crossover Series' Indenture of Trust and pay the related interest and principal.
Acquisition Account or Project Fund	To disburse funds for the acquisition and construction of the Mead-Phoenix, Mead-Adelanto and San Juan projects.
Surplus Fund	To make up any deficiencies in other funds of the Mead Adelanto and Mead-Phoenix projects.

All of the funds listed above, except for the Revolving Fund, are held by the respective trustees.

Palo Verde Project – The balances of the funds required by the Bond Indenture are as follows, in thousands:

	June 30, 1997 Amortized Cost	1997 Fair Value	1996 Amortized Cost	1996 Fair Value
Debt Service Fund -				
Debt Service Account	$ 42,377	$ 41,695	$ 51,386	$ 51,394
Debt Service Reserve Account	67,317	67,332	74,420	74,160
Revenue Fund	1	1	5	5
Operating Fund	25,812	25,830	20,130	20,134
Reserve and Contingency Fund	24,911	24,982	25,924	26,107
Decommissioning Trust Fund	44,399	44,418	34,131	33,740
Issue Fund	24,912	24,738	13,026	13,026
Revolving Fund	52	52	45	45
	$229,781	$229,048	$219,067	$ 218,611
Contractual maturities:				
Within one year	$ 80,473	$ 81,458		
After one year through five years	136,250	134,524		
After five years through ten years	3,238	3,246		
After ten years	9,820	9,820		
	$229,781	$229,048		

Southern Transmission System Project – The balances in the special funds required by the Bond Indenture are as follows, in thousands:

	June 30, 1997 Amortized Cost	1997 Fair Value	1996 Amortized Cost	1996 Fair Value
Construction fund -				
Initial Facilities Account	$ 246	$ 246	$ 235	$ 235
Debt Service Fund -				
Debt Service Account	2,587	2,587	21,921	21,896
Debt Service Reserve Account	21,339	21,379	86,220	86,189
Operating Fund	6,545	6,545	6,015	6,007
General Reserve Fund	11,772	11,772	4,194	4,194
Issue Fund	128,000	129,031	77,024	76,794
Escrow Account - Subordinate				
Refunding Crossover Series	15,439	15,484	346,474	343,903
Revolving Fund	15	15	15	15
	$185,943	$187,059	$542,098	$539,233
Contractual maturities:				
Within one year	$ 62,972	$ 63,412		
After one year through five years	28,819	28,402		
After five years through ten years	43,031	44,123		
After ten years	51,121	51,122		
	$185,943	$187,059		

In addition, at June 30, 1997 and 1996, the Authority had non-interest bearing advances outstanding to IPA of $11,550,000 and $19,550,000, respectively.

Hoover Uprating Project – The balances in the special funds required by the Bond Indenture are as follows, in thousands:

	June 30, 1997 Amortized Cost	1997 Fair Value	1996 Amortized Cost	1996 Fair Value
Operating - Working Capital Fund	$ 1,724	$ 1,721	$ 804	$ 804
Debt Service Fund -				
Debt Service Account	753	753	2,390	2,390
Debt Service Reserve Account	3,126	3,081	3,122	3,121
General Reserve Fund	1,871	1,845	5,318	5,316
Revolving Fund	15	15	–	–
	$ 7,489	$ 7,415	$ 11,634	$ 11,631
Contractual maturities:				
Within one year	$ 7,489	$ 7,415		
	$ 7,489	$ 7,415		

In addition, at June 30, 1997 and 1996, the Authority had advances to USBR of $24,526,000 and $25,183,000, respectively.

Mead-Phoenix Project – The balances in the special funds required by the Bond Indenture are as follows, in thousands:

	June 30, 1997 Amortized Cost	1997 Fair Value	1996 Amortized Cost	1996 Fair Value
Acquisition Account	$ 12,830	$ 12,830	$ 12,571	$ 12,571
Debt Service Fund -				
Debt Service Account	2,904	2,904	4,976	4,967
Debt Service Reserve Account	6,132	6,132	6,133	6,133
Revenue Fund	–	–	64	64
Operating Fund	79	79	239	239
Surplus Fund	88	88	–	–
Revolving Fund	4	4	6	6
	$ 22,037	$ 22,037	$ 23,989	$ 23,980
Contractual maturities:				
Within one year	$ 2,763	$ 3,451		
After one year through five years				
After ten years	19,274	18,586		
	$ 22,037	$ 22,037		

Mead-Adelanto Project – The balances in the special funds required by the Bond Indenture are as follows, in thousands:

	June 30, 1997 Amortized Cost	1997 Fair Value	1996 Amortized Cost	1996 Fair Value
Acquisition Account	$ 39,386	$ 39,387	$ 36,979	$ 36,979
Debt Service Fund -				
Debt Service Account	8,322	8,322	15,194	15,166
Debt Service Reserve Account	16,865	16,865	16,865	16,865
Revenue Fund	–	–	71	71
Operating Fund	–	–	264	264
Surplus Fund	88	88	–	–
Revolving Fund	4	4	6	6
	$ 64,665	$ 64,666	$ 69,379	$ 69,351
Contractual maturities:				
Within one year	$ 4,230	$ 6,287		
After one year through five years	3,349	3,349		
After ten years	57,086	55,030		
	$ 64,665	$ 64,666		

Multiple Project Fund — The balances in the special funds required by the Bond Indenture are as follows, in thousands:

	June 30,			
	1997		1996	
	Amortized Cost	Fair Value	Amortized Cost	Fair Value
Proceeds Account	$256,903	$256,903	$256,830	$256,830
Earnings Account	5,237	5,237	3,278	3,278
	$262,140	$262,140	$260,108	$260,108
Contractual maturities:				
After ten years	$262,140	$262,140		

San Juan Project — The balances in the special funds required by the Bond Indenture are as follows, in thousands:

	June 30,			
	1997		1996	
	Amortized Cost	Fair Value	Amortized Cost	Fair Value
Operating Account	$ 1,932	$ 1,932	$ 1,238	$ 1,238
Operating Reserve	7	7	7	7
Project Fund	553	553	527	527
Debt Service Fund -				
Debt Service Account	9,088	9,088	8,607	8,597
Debt Service Reserve Account	18,026	18,026	18,031	18,031
Reserve and Contingency	15,455	15,452	13,377	13,383
Revolving	10	10		
	$ 45,071	$ 45,068	$ 41,787	$ 41,783
Contractual maturities:				
Within one year	$ 12,084	$ 12,183		
After one year through five years	14,961	14,859		
After ten years	18,026	18,026		
	$ 45,071	$ 45,068		

Projects' Stabilization Fund — At June 30, 1997, the Projects' Stabilization Fund investments had amortized cost and fair value of $14,986,000 and $14,871,000, respectively. All contractual maturities are within one year.

Project Investment Sales — There were no proceeds from sales of investments during fiscal 1997 or 1996.

Note 4 — Long-term Debt:

Reference is made below to the Combined Schedule of Long-term Debt at June 30, 1997 for details related to all of the Authority's outstanding bonds.

Palo Verde Project — To finance the purchase and construction of the Authority's share of the Palo Verde Project, the Authority issued Power Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of July 1, 1981 (Senior Indenture), as amended and supplemented. The Authority also has issued and has outstanding Power Project Subordinate Refunding Series Bonds issued under an Indenture of Trust dated as of January 1, 1993 (Subordinate Indenture). The Subordinate Refunding Bonds were issued to advance refund certain bonds previously issued under the Senior Indenture.

The bond indentures provide that the Revenue Bonds and Subordinate Refunding Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to the Palo Verde Project (see Note 6) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture.

At the option of the Authority, all outstanding Power Project Revenue Bonds and Subordinate Refunding Term Bonds are subject to redemption prior to maturity, except for the 1996 Subordinate Refunding Series A and portions of the 1989A, 1992A, 1992B and 1993A Series bonds which are not redeemable.

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2003 (1986 Series A Bonds and 1987 Series A Bonds), 2005 (1989 Series A Bonds), 2010 (1993 Series A Bonds), and 2008 (1996 Subordinate Refunding Series B). Scheduled principal maturities for the Palo Verde Project during the five fiscal years following June 30, 1997 are $28,570,000 in 1998, $30,195,000 in 1999, $32,040,000 in 2000, $33,815,000 in 2001 and $34,785,000 in 2002. The average interest rate on outstanding debt during fiscal year 1997 and 1996 was 5.2% and 5.8%, respectively.

Southern Transmission System Project — To finance payments-in-aid of construction to IPA for construction of the STS, the Authority issued Transmission Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of May 1, 1983 (Senior Indenture), as amended and supplemented. The Authority also has issued and has outstanding Transmission Project Revenue Bonds 1991 and 1992 Subordinate Refunding Series issued under Indentures of Trust dated as of March 1, 1991 and June 1, 1992, respectively. The 1991 and 1992 subordinated bonds were issued to advance refund certain bonds previously issued under the Senior Indenture.

The bond indentures provide that the Revenue Bonds and the Subordinate Refunding Series Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to STS (see Note 6) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture.

At the option of the Authority, all outstanding Transmission Project Revenue and Refunding Bonds are subject to redemption prior to maturity, except for the 1996 Subordinate Refunding Series A which is not redeemable.

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2019 (for the 1996 Series B Bonds). Scheduled principal maturities for STS during the five fiscal years following June 30, 1997 are $21,360,000 in 1998, $21,970,000 in 1999, $23,110,000 in 2000, $24,455,000 in 2001 and $26,040,000 in 2002. The average interest rate on outstanding debt during fiscal year 1997 and 1996 was 5.1% and 5.6%, respectively.

Hoover Uprating Project — To finance advance payments to USBR for application to the costs of the Hoover Uprating Project, the Authority issued Hydroelectric Power Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of March 1, 1986 (Bond Indenture).

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) the proceeds from the sale of the bonds, (2) all revenues from sales of energy to participants (see Note 6), (3) interest or other receipts derived from any moneys or securities held pursuant to the Bond Indenture and (4) all funds established by the Bond Indenture (except for the Interim Advance Payments Account in the Advance Payments Fund).

At the option of the Authority, all outstanding Hydroelectric Power Project Revenue Bonds are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2007 for the 1991 Series A Bonds maturing on October 1, 2010 and fiscal year 2011 for the 1991 Series A Bonds maturing on October 1, 2017. Scheduled principal maturities for the Hoover Uprating Project during the five fiscal years following June 30, 1997 are $515,000 in 1998, $550,000 in 1999, $580,000 in 2000, $615,000 in 2001 and $650,000 in 2002. The average interest rate on outstanding debt during fiscal year 1997 and 1996 was 6.2% and 6.8%, respectively.

During fiscal 1997, the Authority redeemed $3,565,000 of outstanding Hydroelectric Power Project Revenue Bonds with funds in the Debt Service Fund.

Multiple Project Fund – To finance costs of construction and acquisition of ownership interests or capacity rights in one or more projects expected to be undertaken within five years after issuance, the Authority issued Multiple Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of August 1, 1989 (Bond Indenture), as amended and supplemented.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from, and secured solely by, (1) proceeds from the sale of bonds, (2) with respect to each authorized project, the revenues of such authorized project, and (3) all funds established by the Bond Indenture.

In October 1992, $103,640,000 and $285,010,000 of the Multiple Project Revenue Bonds were transferred to the Mead-Phoenix Project and the Mead-Adelanto Project, respectively, to finance the estimated costs of acquisition and construction of the projects.

A total of $153,500,000 of the outstanding Multiple Project Revenue Bonds are not subject to redemption prior to maturity. At the option of the Authority, the balance of the outstanding bonds are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2006 for the 1989 Series Bonds. The first scheduled principal maturities for the Multiple Project Revenue Bonds for fiscal years following June 30, 1997 are $5,400,000 in 2000, $5,800,000 in 2001 and $6,200,000 in 2002. The average interest rate on outstanding debt during fiscal year 1997 and 1996 was 6.4%.

Mead-Phoenix Project – To finance the Authority's ownership interest in the estimated cost of the project, $103,640,000 of the Multiple Project Revenue Bonds were transferred to the Mead-Phoenix Project in October 1992. In March 1994, the Authority issued and has outstanding $51,835,000 of Mead-Phoenix Revenue Bonds under an Indenture of Trust dated as of January 1, 1994 (Bond Indenture). The proceeds from the Revenue Bonds, together with drawdowns from the Debt Service Fund and Project Acquisition Fund, were used to advance refund $64,840,000 of the Multiple Project Revenue Bonds previously transferred to the Mead-Phoenix Project.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from, and secured solely by, (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to Mead-Phoenix (see Note 6) and interest on all moneys or securities and (3) all funds established by the Bond Indenture.

At the option of the Authority, all outstanding Mead-Phoenix Revenue Bonds are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2018 for the 1994 Series Bonds. The first scheduled principal maturities for the Mead-Phoenix Revenue Bonds for fiscal years following June 30, 1997 are $2,160,000 in 2000, $2,320,000 in 2001 and $2,480,000 in 2002. The average interest rate on outstanding debt during fiscal year 1997 and 1996 was 6.3%.

Mead-Adelanto Project – To finance the Authority's ownership interest in the estimated cost of the project, $285,010,000 of the Multiple Project Revenue Bonds were transferred to the Mead-Adelanto Project in October 1992. In March 1994, the Authority issued and has outstanding $173,955,000 of Mead-Adelanto Revenue Bonds under an Indenture of Trust dated as of January 1, 1994 (Bond Indenture). The proceeds of the Revenue Bonds, together with drawdowns from the Debt Service Fund and Project Acquisition Fund, were used to advance refund $178,310,000 of the Multiple Project Revenue Bonds previously transferred to the Mead-Adelanto Project.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from, and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to Mead-Adelanto (see Note 6) and interest on all moneys or securities and (3) all funds established by the Bond Indenture.

At the option of the Authority, all outstanding Mead-Adelanto Revenue Bonds are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2018 for the 1996 Series Bonds. The first scheduled principal maturities for the Mead-Adelanto Revenue Bonds for fiscal years following June 30, 1997 are $5,940,000 in 2000, $6,380,000 in 2001 and $6,820,000 in 2002. The average interest rate on outstanding debt during fiscal year 1997 and 1996 was 5.6%.

San Juan Project – To finance the costs of acquisition of an ownership interest in Unit 3 of the SJGS, the Authority issued San Juan Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of January 1, 1993 (Bond Indenture).

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from, and secured solely by, (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to San Juan (see Note 6) and interest on all moneys or securities and (3) all funds established by the Bond Indenture.

At the option of the Authority, all outstanding San Juan Project Revenue Bonds are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2012 for the 1993 Series A Bonds. The scheduled principal maturities for the San Juan Project Revenue Bonds during the five fiscal years following June 30, 1997 are $6,275,000 in 1998, $6,540,000 in 1999, $6,825,000 in 2000, $7,140,000 in 2001 and $7,480,000 in 2002. The average interest rate on outstanding debt during fiscal year 1997 and 1996 was 5.3%.

Refunding Bonds – In July 1992, the Authority issued $475,000,000 of Southern Transmission Project Revenue Bonds to refund $385,385,000 of previously issued bonds. Principal and interest with respect to the 1992 bonds were allocated into four separate components. Each of components 1, 2 and 3 were secured by, and payable from, investments in its escrow fund until scheduled crossover dates. Component 4 proceeds of $14,100,000 were used to advance refund approximately $9,000,000 of bonds in fiscal year 1993. On the Component 1 Crossover date (January 1, 1994), Component 1 proceeds of $13,959,000 were used in fiscal 1994 to advance refund $13,455,000 of previously issued bonds. On the Component 2 Crossover date (January 1, 1995), Component 2 proceeds of $5,519,000 were used in fiscal 1995 to advance refund $5,335,000 of previously issued bonds. On the Component 3 Crossover date (July 1, 1996), Component 3 proceeds of $321,069,000 were used in fiscal 1997 to advance refund $313,050,000 of previously issued bonds.

In September 1996, the Authority issued $42,245,000 of Southern Transmission Project Revenue Bonds, 1996 Subordinate Refunding Series A and $121,065,000 of Southern Transmission Project Revenue Bonds, 1996 Subordinate Refunding Series B to refund $68,720,000 and $127,100,000 of the STS 1986 Refunding Series A and B, respectively. The refunding is expected to reduce total debt service payments over the next 26 years by approximately $125,382,000 (the difference between the debt service payments on the old and new debt) and is expected to result in a net present value savings of approximately $32,526,000.

In January 1992, $70,680,000 of Palo Verde Special Obligation Crossover Series Bonds, were issued, the proceeds of which were placed in an irrevocable trust to redeem $69,125,000 of previously issued bonds. On July 1, 1996, trust assets held in escrow of $63,415,000 were used to advance refund $62,000,000 of previously issued bonds.

In August 1996, the Authority issued $89,570,000 of Palo Verde 1996 Subordinate Refunding Series C bonds to refund $95,015,000 of 1986 Refunding Series B bonds. The refunding is expected to reduce total debt service payments over the next 20 years by approximately $24,713,000 (the difference between the debt service payments on the old and new debt) and is expected to result in a net present value savings of approximately $16,955,000.

In April 1996, the Authority issued $152,905,000 of Palo Verde 1996 Subordinate Refunding Series A Bonds to refund $163,355,000 of previously issued Palo Verde 1987 Refunding Series A Bonds and issued $58,870,000 of Palo Verde 1996 Subordinate Refunding Series B Bonds to refund $18,555,000 and $40,315,000 of previously issued Palo Verde 1986 Refunding Series B and 1987 Refunding Series A Bonds, respectively. The refunding is expected to reduce total debt service payments over the next 13 years by approximately $50,967,000 (the difference between the debt service payments on the old and new debt) and is expected to result in a net present value savings of approximately $29,537,000.

On July 1, 1995, the crossover date for the Palo Verde Special Obligation Bonds Series A, trust assets in escrow of $7,131,000 were used to advance refund $7,125,000 of previously issued bonds.

In March 1994, the Authority issued $51,835,000 of Mead-Phoenix Project Revenue Bonds and $173,955,000 of Mead-Adelanto Project Revenue Bonds to refund $243,150,000 of previously issued Multiple Project Revenue Bonds which were transferred to the Mead-Phoenix and Mead-Adelanto projects during fiscal year 1993. The partial refunding of the original issue within five years of its issuance triggered a recalculation of the arbitrage yield. The recalculation resulted in a higher arbitrage yield which reduced the rebate liability of the Authority. At June 30, 1997, cumulative savings due to the rebate calculation amounted to $7,345,000. This amount was allocated $1,959,000 and $5,386,000 to the Mead-Phoenix and Mead-Adelanto Projects, respectively, and is recorded as accounts receivable in the accompanying combined balance sheet.

At June 30, 1997 and 1996, the aggregate amount of debt in all projects considered to be defeased was $3,543,995,000 and $3,535,075,000, respectively.

Interest Rate Swap – In fiscal year 1991, the Authority entered into an Interest Rate Swap agreement with a third party for the purpose of hedging against interest rate fluctuations arising from the issuance of the Southern Transmission Project Revenue Bonds, 1991 Subordinate Refunding Series as variable rate obligations. The notional amount of the Swap Agreement is equal to the par value of the bond ($291,000,000 and $291,700,000 at June 30, 1997 and 1996, respectively). The Swap Agreement provides for the Authority to make payments to the third party on a fixed rate basis at 6.38%, and for the third party to make reciprocal payments based on a variable rate basis (3.9% and 3.1% at June 30, 1997 and 1996, respectively). The bonds mature in 2019.

COMBINED SCHEDULE OF LONG-TERM DEBT
AT JUNE 30, 1997
(In thousands)

Project	*Series*	*Date of Sale*	*Effective Interest Rate*	*Maturity on July 1*	*Total*
Principal:					
Palo Verde Project Revenue and Refunding Bonds	1986A	03/13/86	8.2%	1997 to 2006	$ 7,765
	1987A	02/11/87	6.9%	1997 to 2017	40,140
	1989A	02/15/89	7.2%	1997 to 2015	281,585
	1992A	01/01/92	6.0%	1997 to 2010	7,155
	1992B	01/01/92	6.0%	1997 to 2006	63,415
	1992C	01/01/92	6.0%	1997 to 2010	10,635
	1993Sub	03/01/93	5.5%	1997 to 2017	98,200
	1993A	03/01/93	5.5%	1997 to 2017	268,710
	1996A	02/13/96	4.4%	1997 to 2017	152,905
	1996B	02/29/96	4.4%	1997 to 2017	58,870
	1996C	08/22/96	4.2%	2016 to 2017	89,570
					1,078,950
Southern Transmission System Project Revenue and Refunding Bonds	1988A	11/22/88	7.2%	1997 to 2015	154,085
	1991A	04/17/91	6.4%	2019	291,000
	1992 Comp 1, 2, 4	07/20/92	6.1%	1997 to 2021	35,705
	1992 Comp 3	07/20/92	6.1%	1997 to 2021	423,559
	1993A	07/01/93	5.4%	1997 to 2023	119,940
	1996A	09/12/96	4.9%	1997 to 2006	42,245
	1996B	09/12/96	4.3%	2019 to 2023	121,065
					1,187,599
Hoover Uprating Project Revenue and Refunding Bonds	1991	08/01/91	6.2%	1997 to 2017	31,005
Multiple Project Revenue Bonds					
Mead-Phoenix Project	1989	01/04/90	7.1%	1999 to 2013	38,800
Mead-Adelanto Project	1989	01/04/90	7.1%	1999 to 2013	106,700
Multiple Project	1989	01/04/90	7.1%	1999 to 2020	259,100
					404,600
Mead-Phoenix Project Revenue Bonds	1994A	03/01/94	5.3%	2006 to 2020	51,835
Mead-Adelanto Project Revenue Bonds	1994A	03/01/94	5.3%	2006 to 2020	173,955
San Juan Project Revenue Bonds	1993	06/01/93	5.6%	1997 to 2020	231,340
Total principal amount					3,159,284
Unamortized bond discount:					
Palo Verde Project					(85,229)
Southern Transmission System Project					(100,362)
Hoover Uprating Project					(3,491)
Mead-Phoenix Project					(4,065)
Mead-Adelanto Project					(12,199)
Multiple Project Fund					(15,634)
San Juan Project					(8,569)
Total unamortized bond discount					(229,549)
Long-term debt due within one year					(56,720)
Total long-term debt, net					$ 2,873,015

Note – bonds which have been refunded are excluded from this schedule

Note 5 — Disclosures about Fair Value of Financial Instruments:
The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and cash equivalents — The carrying value approximates fair value because of the short maturity of those instruments.

Investments/Decommissioning fund/Escrow account — Subordinate Refunding Crossover Series/Crossover escrow accounts — The fair values of investments are estimated based on quoted market prices for the same or similar investments.

Long-term debt/Special Obligation Crossover Series Bonds/Subordinate Refunding Crossover Series — The fair value of the Authority's debt is estimated based on the quoted market prices for the same or similar issues or on the current average rates offered to the Authority for debt of approximately the same remaining maturities, net of the effect of a related interest rate swap agreement.

The fair values of the Authority's financial instruments are as follows (in thousands):

	June 30,			
	1997		1996	
	Amortized Cost	Fair Value	Amortized Cost	Fair Value
Assets:				
Cash and cash equivalents	$ 87,370	$ 87,370	$ 173,798	$ 173,798
Escrow account - Subordinate Refunding Crossover Series	15,439	15,484	346,468	343,898
Decommissioning fund	43,924	43,943	33,865	33,474
Investments	670,711	670,837	597,831	597,427
Liabilities:				
Debt	2,929,735	3,211,927	2,920,735	3,210,790
Subordinate Refunding Crossover Series	–	–	347,388	385,516
Off Balance Sheet Financial Instruments:				
Special Obligation Crossover Series Bonds	–	–	63,415	67,739
Crossover escrow accounts	–	–	63,849	63,849

Note 6 — Power Sales and Transmission Service Contracts:
The Authority has power sales contracts with ten participants of the Palo Verde Project (see Note 1). Under the terms of the contracts, the participants are entitled to power output from the PVNGS and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Power Project Revenue Bonds and other debt. The contracts expire in 2030 and, as long as any Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

The Authority has transmission service contracts with six participants of the Southern Transmission System Project (see Note 1). Under the terms of the contracts, the participants are entitled to transmission service utilizing the Southern Transmission System Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Transmission Project Revenue Bonds and other debt. The contracts expire in 2027 and, as long as any Transmission Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

In March 1986, the Authority entered into power sales contracts with six participants of the Hoover Uprating Project (see Note 1). Under the terms of the contracts, the participants are entitled to capacity and associated firm energy of the Hoover Uprating Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service whether or not the Hoover Uprating Project or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The contracts expire in 2018, and as long as any Hydroelectric Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

In August 1992, the Authority entered into transmission service contracts with nine participants of the Mead-Phoenix Project (see Note 1). Under the terms of the contracts, the participants are entitled to transmission service utilizing the Mead-Phoenix Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on the Multiple Project and Mead-Phoenix Revenue Bonds and other debt, whether or not the Mead-Phoenix Project or any part thereof has been completed, is operating and operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The contracts expire in 2030 and, as long as any Multiple Project and Mead-Phoenix Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

In August 1992, the Authority entered into transmission service contracts with nine participants of the Mead-Adelanto Project (see Note 1). Under the terms of the contracts, the participants are entitled to transmission service utilizing the Mead-Adelanto Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on the Multiple Project and Mead-Adelanto Revenue Bonds and other debt, whether or not the Mead-Adelanto Project or any part thereof has been completed, is operating and operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The contracts expire in 2030 and, as long as any Multiple Project and Mead-Adelanto Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

In January 1993, the Authority entered into power sales contracts with five participants of Unit 3 of the San Juan Project (see Note 1). Under the terms of the contracts, the participants are entitled to their proportionate share of the power output of the San Juan Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on the San Juan Revenue Bonds, whether or not Unit 3 of the San Juan Project or any part thereof is operating or operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The contracts expire in 2030 and, as long as any San Juan Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

Note 7 — Costs Recoverable from Future Billings to Participants:

Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. Those expenses, according to generally accepted accounting principles (GAAP), which are not included as "costs" are deferred to such periods when it is intended that they be recovered through billings for the repayment of principal on related debt.

Costs recoverable from future billings to participants are comprised of the following (in thousands):

	Balance June 30, 1996	Fiscal 1997 Activity	Balance June 30, 1997
GAAP items not included in billings to participants:			
Depreciation of plant	$ 397,651	$ 53,156	$ 450,807
Amortization of bond discount, debt issue costs, and cost of refunding	268,899	57,968	326,867
Nuclear fuel amortization	19,548	–	19,548
Decommissioning expense	82,843	6,702	89,545
Interest expense	30,899	9,769	40,668
Bond requirements included in billings to participants:			
Operations and maintenance, net of investment income	($ 88,315)	(13,955)	(102,270)
Costs of acquisition of capacity - STS	(18,350)	–	(18,350)
Reduction in debt service billings due to transfer of excess funds	67,559	99	67,658
Principal repayments	(261,689)	(56,086)	(317,775)
Other	(35,598)	(3,906)	(39,504)
	$ 463,447	$ 53,747	$ 517,194

In March 1997, the Palo Verde Project participants approved a board resolution which instructs the Authority to increase fiscal 1998 and future billings to Palo Verde participants so as to fully amortize the current costs recoverable from future billings to participants balance of $230,497,000 at June 30, 1997 by June 30, 2003 and to prevent the further accumulation of costs recoverable from future billings to participants.

Note 8 — Commitments and Contingencies:

In September 1996, Assembly Bill 1890 (Bill) was given final approval. The Bill, which provides for broad deregulation of the power generation industry in California, requires the participation of the state's investor-owned utilities. Consumer-owned utilities can participate on a voluntary basis but must hold public hearings as part of their decision making process. The Bill, which was supported by the Authority, authorizes the collection of a transition charge for generation when a consumer-owned utility opens its service area to competition and participates in the independent transmission system established by the legislation. The Bill also mandates the collection of a public benefit charge from all electric utility customers in the state. Although these funds (currently estimated at 2.5% of gross revenues) must be spent on renewable resources, conservation, research and development, or low income rate subsidies, the governing authority of each consumer-owned utility will control actual expenditures.

The Price-Anderson Act (the "Act") requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. The Act limits liability from third-party claims to $8.9 billion per incident. Participants in the Palo Verde Nuclear Generating Station currently insure potential claims and liability through commercial insurance with a $200 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to $79.3 million for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $10 million, per incident, per year. Based on the Authority's 5.91% interest in Palo Verde, the Authority would be responsible for a maximum assessment of $4.7 million, limited to payments of $591,000 per incident, per year.

The Authority is involved in various legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position of the Authority or the respective separate projects.

Note 9 — Restatement of Prior Years Comparative Financial Statements:

Hoover Uprating Project – The Authority has restated prior year comparative financial statements for the Hoover Uprating Project to reflect the application of credits on billings to participants for energy and capacity which reduce advance payments made to USBR (Note 2) in accordance with Procedures and Practices for the Administration of Section 6.5 of the Electric Service Contracts dated June 1996. The effect of the restatement on Costs recoverable from future billings to participants in the statement of operations for the year ended June 30, 1996 is as follows (in thousands):

	Hoover Uprating Project
Costs recoverable from future billings to participants as previously reported	($ 239)
Adjustment for effect of restatement	892
Costs (recoverable from) in excess of future billings to participants as adjusted	$ 653

Advances for capacity and energy, net and Costs recoverable from future billings to participants at July 1, 1995 have also been increased and reduced, respectively, by $14,172,000 to reflect the retroactive effect of the restatement on beginning Advances for capacity and energy, net and Costs recoverable from future billings to participants.

Palo Verde Project – The Authority has restated prior year comparative financial statements for the Palo Verde Project to reflect amortization over the remaining life of the bond of debt issue costs associated with the issuance of the Palo Verde Refunding Bond Series 1985 A and B.

Unamortized debt expenses and Costs recoverable from future billings to participants at July 1, 1995 have been reduced and increased, respectively, by $12,981,000 to reflect the retroactive effect of the restatement on beginning Unamortized debt expenses and Costs recoverable from future billings to participants. The restatement had no effect on Costs recoverable from future billings to participants for the year ended June 30, 1996.

Southern Transmission System Project — The Authority has restated prior year comparative financial statements for the Southern Transmission System Project to reflect amortization over the remaining life of the bond of debt issue costs associated with the issuance of the Southern Transmission System Project Refunding Bond Series 1985A. The Authority has also restated prior year comparative financial statements for the Southern Transmission System Project to reflect bond discount amortization over the life of the Southern Transmission System Project Refunding Bond Series 1992 Component 3.

The effect of the restatements on Costs recoverable from future billings to participants in the statement of operations for the year ended June 30, 1996 is as follows (in thousands):

	Southern Transmission System Project
Costs recoverable from future billings to participants as previously reported	($ 20,633)
Adjustment for effect of restatement	(3,544)
Costs recoverable from future billings to participants as adjusted	($ 24,177)

Unamortized debt expenses, Unamortized bond discount and Costs recoverable from future billings to participants at July 1, 1995 have also been (reduced)/increased by ($559,000), ($7,600,000) and $8,159,000, respectively, to reflect the retroactive effect of the restatement on beginning Unamortized debt expenses, Unamortized bond discount and Costs recoverable from future billings to participants.

Combined Total — The effect of these restatements on the combined total of Costs recoverable from future billings to participants in the statement of operations for the year ended June 30, 1996 is as follows (in thousands):

	Combined Total
Costs recoverable from future billings to participants as previously reported	($ 42,796)
Adjustment for effect of restatement	(2,652)
Costs recoverable from future billings to participants as adjusted	($ 45,448)

Advances for capacity and energy, net, Unamortized debt expenses, Unamortized bond discount and Costs recoverable from future billings to participants at July 1, 1995 have also been increased (reduced) by $14,172,000, ($13,540,000), ($7,600,000) and $6,968,000, respectively, to reflect the retroactive effect of the restatement on beginning Advances for capacity and energy, net, Unamortized debt expenses, Unamortized bond discount and Costs recoverable from future billings to participants.

Note 10 — Subsequent Event (Unaudited):

On October 9, 1997, the Authority issued $375,650,000 in Palo Verde Project bonds as part of a comprehensive Restructuring Plan. The bonds consist of $29,975,000 of tax-exempt bonds with an effective interest rate of 4.4%, 1997 Series A, and $345,675,000 of taxable bonds with an effective interest rate of 7.0%, 1997 Series B. The Series A bonds will be used to advance refund $25,745,000 of 1989 Refunding Series A and $2,945,000 of 1992 Refunding Series C. Whereas, 1997 Series B will be used to refund $9,895,000 of 1992 Refunding Series B; $1,980,000 of 1992 Refunding Series C; $238,295,000 of 1993 Refunding Series A; $98,200,000 of 1993 Subordinate Refunding Series; and $74,475,000 of 1996 Subordinate Refunding Series A; which are restricted from being refunded on a tax-exempt basis. These bonds will be defeased to maturity with the proceeds from the taxable bond issue. The taxable bonds were structured as a bullet term bond maturing in 2017.

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SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
PALO VERDE PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 1997

(In thousands)

	Debt Service Fund	Revenue Fund	Operating Fund	Reserve & Contingency Fund	Issue Fund	Decommissioning Funds I & II	Total
Balance at June 30, 1996	$ 124,685	$ 4	$ 19,949	$ 25,582	$ 13,017	$ 33,530	$ 216,767
Additions:							
Investment earnings	3,944	34	1,134	1,110	663	1,630	8,515
Distribution of investment earnings	(4,722)	8,191	(1,153)	(1,538)	(778)		–
Discount on investment purchases	723	30	96	432	115	853	2,249
Revenue from power sales	81	121,355	19	24			121,479
Distribution of revenues	51,719	(126,281)	40,679	2,304	23,583	7,996	–
Transfers to escrow for refundings	(7,649)	(3,333)	258	(1,000)	5,433		(6,291)
Transfer from escrow for principal and interest payments	717,338						717,338
Total	761,434	(4)	41,033	1,332	29,016	10,479	843,290
Deductions:							
Construction expenditures				2,363			2,363
Operating expenditures			27,368		104	5	27,477
Fuel costs			8,044				8,044
Bond issue costs					1,585		1,585
Payment of principal	25,690						25,690
Interest paid	35,019				15,603		50,622
Premium and interest paid on investments	24				6	118	148
Payment of principal and interest on escrow bonds	717,338						717,338
Total	778,071	–	35,412	2,363	17,298	123	833,267
Balance at June 30, 1997	$ 108,048	$ –	$ 25,570	$ 24,551	$ 24,735	$ 43,886	$ 226,790

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $1,471 and $1,245 and Decommissioning Fund accrued interest receivable of $475 and $267 at June 30, 1997 and 1996, respectively, nor do they include total amortized net investment discounts of $1,045 and $788 at June 30, 1997 and 1996, respectively. These balances also do not include unrealized loss on investments in funds available for sale of $733 and $456 at June 30, 1997 and 1996, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SOUTHERN TRANSMISSION SYSTEM PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 1997

(In thousands)

	Construction Fund-Initial Facilities Account	Debt Service Fund	Operating Fund	General Reserve Fund	Issue Fund	Escrow Fund	Total
Balance at June 30, 1996	$ 234	$ 106,411	$ 6,051	$ 4,157	$ 76,219	$ 343,874	$ 536,946
Additions:							
Bond interest received					254		254
Investment earnings	11	3,639	450	328	6,964		11,392
Distribution of investment earnings		(3,238)	10,499	(327)	15,897	(22,831)	–
Revenue from transmission sales			91,689				91,689
Distribution of revenue		(26,158)	(87,758)	7,561	86,415	19,940	–
Transfer from escrow for principal and interest payments		202,372					202,372
Other receipts		55	42		12		109
Total	11	176,670	14,922	7,562	109,542	(2,891)	305,816
Deductions:							
Operating expenses			14,437				14,437
Payment of principal					10,845		10,845
Interest paid		25,507			47,682		73,189
Payment for defeasance of revenue bonds		31,310				326,539	357,849
Payment of principal and interest on escrow bonds		202,372					202,372
Premium and interest paid on investment purchases		172			59		231
Bond issue costs		174			3,228		3,402
Total		259,535	14,437		61,814	326,539	662,325
Balance at June 30, 1997	$ 245	$ 23,546	$ 6,536	$ 11,719	$ 123,947	$ 14,444	$ 180,437

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $583 and $2,169 at June 30, 1997 and 1996, respectively, nor do they include total amortized net investment discounts of $4,923 and $2,983 at June 30, 1997 and 1996, respectively. These balances do not include unrealized (gain) loss on investments in funds available for sale of ($1,116) and $2,865 at June 30, 1997 and 1996, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
HOOVER UPRATING PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 1997

(In thousands)

	Advance Payments Fund	*Operating Fund*	*Revenue Fund*	*Working Capital Fund*	*Debt Service Account*	*Debt Service Reserve Account*	*General Reserve Fund*	*Total*
Balance at June 30, 1996	$ –	$ 238	$ –	$ 560	$ 2,371	$ 3,083	$ 5,259	$ 11,511
Additions:								
Investment earnings		60	5		27	36	25	153
Distribution of investment earnings		(60)	476		(58)	(178)	(180)	–
Discount on investment purchases					31	142	155	328
Revenue from power sales			2,553					2,553
Distribution of revenues		508	(2,014)		1,284		222	–
Transfer from escrow for interest payments					30,260			30,260
Miscellaneous transfers		804	(1,020)		3,852		(3,636)	–
Total	–	1,312	–	–	35,396	–	(3,414)	33,294
Deductions:								
Payment of principal					4,650			4,650
Administrative expenditures		335						335
Interest paid					1,855			1,855
Payment of interest on escrow bonds					30,260			30,260
Other		43			252			295
Total	–	378	–	–	37,017	–	–	37,395
Balance at June 30, 1997	$ –	$ 1,172	$ –	$ 560	$ 750	$ 3,083	$ 1,845	$ 7,410

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $6 at June 30, 1997 and 1996, nor do they include total amortized net investment discount of $73 and $117 at June 30, 1997 and 1996, respectively. These balances also do not include unrealized loss on investments in funds available for sale of $74 and $3 at June 30, 1997 and 1996, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-PHOENIX PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 1997

(In thousands)

	Acquisition Account	*Debt Service Account*	*Debt Service Reserve Account*	*Revenue Fund*	*Issue Fund*	*Operating Fund*	*Surplus Fund*	*Total*
Balance at June 30, 1996	$ 12,080	$ 2,367	$ 5,916	$ 65	$ 2,525	$ 237	$ –	$ 23,190
Additions:								
Investment earnings	950	145	435	3	82	14	2	1,631
Transfer of investments		(930)	(435)		1,365			–
Reimbursement from WAPA				222				222
Transmission revenue				2,912				2,912
Transfer of monthly transmission costs				(502)		416	86	–
Transfer of funds		2,550		(2,700)		150	–	–
Total	950	1,765	–	(65)	1,447	580	88	4,765
Deductions:								
Construction expenditures	364							364
Interest paid		2,642			2,534			5,176
Premium and interest paid on investment purchases					58			58
Operating expenses	289					739		1,028
Total	653	2,642			2,592	739		6,626
Balance at June 30, 1997	$ 12,377	$ 1,490	$ 5,916	$ –	$ 1,380	$ 78	$ 88	$ 21,329

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $690 and $841 at June 30, 1997 and 1996, respectively, nor do they include total amortized net investment discount of $18 and premium of $42 at June 30, 1997 and 1996, respectively. These balances do not include unrealized loss on investments in funds available for sale of $9 at June 30, 1996.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-ADELANTO PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 1997

(In thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Operating Fund	Issue Fund	Revenue Fund	Surplus Fund	Total
Balance at June 30, 1996	$ 35,665	$ 6,497	$ 16,267	$ 263	$ 8,474	$ 71	$	$ 67,237
Additions:								
Investment earnings	2,667	384	1,196	14	274	8	2	4,545
Transfer of investment earnings		1,196	(1,196)					–
Reimbursement from WAPA						15		15
Transfers of funds		3,048		150	4,301	(7,585)	86	–
Transmission revenue						7,943		7,943
Transfer of monthly transmission costs				452		(452)		–
Total	2,667	4,628	–	616	4,575	(71)	88	12,503
Deductions:								
Construction expenditures	(1)							(1)
Interest paid		7,270			8,505			15,775
Premium and interest paid on investment purchases		(1)			195			194
Operating expenses	365			851				1,216
Total	364	7,269		851	8,700	–		17,184
Balance at June 30, 1997	$ 37,968	$ 3,856	$ 16,267	$ 28	$ 4,349	$ –	$ 88	$ 62,556

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $2,057 and $2,285 at June 30, 1997 and 1996, respectively, nor do they include total amortized net investment discount of $53 and premium of $143 at June 30, 1997 and 1996, respectively. These balances do not include unrealized loss on investments in funds available for sale of $1 and $28 at June 30, 1997 and 1996, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MULTIPLE PROJECT FUND
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 1997

(In thousands)

	Proceeds Account	Debt Service Account	Earnings Account	Total
Balance at June 30, 1996	$ 249,423	$ –	$ 1,465	$ 250,888
Additions:				
Investment earnings	18,208		268	18,476
Transfer to earnings account	(18,208)		18,208	–
Transfer to debt service account		16,512	(16,512)	–
Total	–	16,512	1,964	18,476
Deductions:				
Interest paid		16,512		16,512
Other transfers	(1,696)		1,696	–
Total	(1,696)	16,512	1,696	16,512
Balance at June 30, 1997	$ 247,727	$ –	$ 5,125	$ 252,852

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of investments at original cost. These balances do not include accrued interest receivable of $9,288 and $9,220 at June 30, 1997 and 1996, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 1997

(In thousands)

	Revenue Fund	Operating Account	Operating Reserve Account	Project Fund	Debt Service	Debt Service Reserve	Reserve & Contingency	Total
Balance at June 30, 1996	$ –	$ 1,253	$ 5	$ 526	$ 8,521	$ 18,025	$ 13,321	$ 41,651
Additions:								
Investment earnings	42	60		25	38	1,066	534	1,765
Distribution of investment earnings	2,221	(73)		(2)	(311)	(1,066)	(769)	–
Discount on investment purchases	–	7		1	279		241	528
Revenue from power sales	56,866							56,866
Distribution of revenues	(56,330)	35,689			18,514		2,127	–
Transfer of investment earnings	(2)			2				–
Miscellaneous transfers	(2,797)	2,797						–
Total	–	38,480		26	18,520	–	2,133	59,159
Deductions:								
Administrative expenditures		37,794						37,794
Interest paid					11,988			11,988
Premium and interest on investment purchases					6		110	116
Principal payment					6,035			6,035
Total		37,794			18,029		110	55,933
Balance at June 30, 1997	$ –	$ 1,939	$ 5	$ 552	$ 9,012	$ 18,025	$ 15,344	$ 44,877

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $134 and $67 at June 30, 1997 and 1996, respectively, nor do they include total amortized net investment discount of $60 and $69 at June 30, 1997 and 1996, respectively. These balances do not include unrealized loss on investments in funds available for sale of $3 and $4 at June 30, 1997 and 1996, respectively.