- --
- --

FORM 10-K

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

FOR THE FISCAL YEAR ENDED DECEMBER 31, 1997
COMMISSION FILE NUMBER 1-1402

SOUTHERN CALIFORNIA GAS COMPANY

(Exact name of Registrant as specified in its charter)

CALIFORNIA	95-1240705
(State of incorporation)	(IRS Employer Identification No.)
555 WEST FIFTH STREET, LOS ANGELES, CALIFORNIA	90013-1011
(Address of principal executive offices)	(Zip Code)

(213) 244-1200
(Registrant's telephone number, including area code)

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

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Preferred Stock	Pacific Stock Exchange
6% Cumulative Preferred--Series A	
7 3/4% Series Preferred Stock	
First Mortgage Bonds	New York Stock Exchange
Series Y, due 2021 (8 3/4%)	
Series Z, due 2002 (6 7/8%)	
Series AA, due 1997 (6 1/2%)	
Series BB, due 2023 (7 3/8%)	
Series CC, due 1998 (5 1/4%)	
Series DD, due 2023 (7 1/2%)	
Series EE, due 2025 (6 7/8%)	
Series FF, due 2003 (5 3/4%)	

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

----

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

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

The aggregate market value of Registrant's voting stock (Preferred Stock) held by non-affiliates at March 16, 1998, was approximately $22 million. This amount excludes the market value of 50,477 shares of Preferred Stock held by Registrant's parent, Pacific Enterprises. All of the Registrant's Common Stock is owned by Pacific Enterprises.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information in this Annual Report is incorporated by reference to information contained or to be contained in other documents filed or to be filed by Registrant with the Securities and Exchange Commission. The following table identifies the information so incorporated in each Part of this Annual Report on Form 10-K and the document in which it is or will be contained.

ANNUAL REPORT ON FORM 10-K	INFORMATION INCORPORATED BY REFERENCE AND DOCUMENT IN WHICH INFORMATION IS OR WILL BE CONTAINED
Part III	Information contained under the captions "Election of Directors," "Share Ownership of Directors and "Executive Officers" and "Executive Compensation" in Registrant's Information Statement for its Annual Meeting of Shareholders scheduled to be held on May 5, 1998.

- ---
- ---

TABLE OF CONTENTS

PART I

THIS REPORT CONTAINS FORWARD-LOOKING STATEMENTS WITH RESPECT TO MATTERS INHERENTLY INVOLVING NUMEROUS RISKS AND UNCERTAINTIES. THESE STATEMENTS ARE IDENTIFIED BY THE WORDS "ESTIMATES," "EXPECTS," "ANTICIPATES," "PLANS," "BELIEVES," AND SIMILAR EXPRESSIONS.

THESE STATEMENTS ARE NECESSARILY BASED UPON VARIOUS ASSUMPTIONS INVOLVING JUDGMENTS WITH RESPECT TO THE FUTURE INCLUDING, AMONG OTHER FACTORS, NATIONAL, REGIONAL, AND LOCAL ECONOMIC, COMPETITIVE AND REGULATORY CONDITIONS, TECHNOLOGICAL DEVELOPMENTS, INFLATION RATES, INTEREST RATES, ENERGY MARKETS, WEATHER CONDITIONS, BUSINESS AND REGULATORY DECISIONS, AND OTHER UNCERTAINTIES, ALL OF WHICH ARE DIFFICULT TO PREDICT, AND MANY OF WHICH ARE BEYOND THE CONTROL OF SOUTHERN CALIFORNIA GAS COMPANY. ACCORDINGLY, WHILE SOUTHERN CALIFORNIA GAS COMPANY BELIEVES THESE ASSUMPTIONS ARE REASONABLE, THERE CAN BE NO ASSURANCE THAT THEY WILL APPROXIMATE ACTUAL EXPERIENCE, OR THAT THE EXPECTATIONS WILL BE REALIZED.

PART I

ITEM 1. BUSINESS

Southern California Gas Company ("The Gas Company" or the "Company") is a public utility owning and operating a natural gas distribution, transmission and storage system that supplies natural gas in 535 cities and communities throughout a 23,000-square-mile service territory comprising most of southern and part of central California. The Gas Company is the principal subsidiary of Pacific Enterprises (the "Parent").

The Gas Company is the nation's largest natural gas distribution utility. It provides gas service to residential, commercial, industrial, utility electric generation and wholesale customers through approximately 4.8 million meters in a service area with a population of approximately 17.6 million.

The Gas Company was incorporated in California in 1910. Its principal executive offices are located at 555 West Fifth Street, Los Angeles, California 90013 and its telephone number is (213) 244-1200.

OPERATING STATISTICS

The following table sets forth certain operating statistics of SoCalGas from 1993 through 1997.

	YEAR ENDED DECEMBER 31				
	1997	1996	1995	1994	1993
Gas Sales, Transportation & Exchange					
Revenues (millions of dollars):					
Residential	$ 1,736	$ 1,613	$ 1,554	$ 1,713	$ 1,652
Commercial/Industrial	756	708	751	798	854
Utility Electric Generation	76	70	104	118	147
Wholesale	67	70	62	98	117
Exchange	1	1	1	1	4
Total in rates (1)	2,636	2,462	2,472	2,728	2,774
Regulatory balancing accounts and other	5	(40)	(193)	(142)	37
Operating Revenue	$ 2,641	$ 2,422	$ 2,279	$ 2,586	$ 2,811
Volumes (billions of cubic feet):					
Residential	240	236	239	256	247
Commercial/Industrial	388	374	352	348	340
Utility Electric Generation	158	139	204	260	213
Wholesale	138	130	129	146	148
Exchange	6	5	13	10	17
Total	930	884	937	1,020	965
Core	323	314	325	341	339
Noncore	607	570	612	679	626
Total	930	884	937	1,020	965
Sales	317	315	338	362	352
Transportation	607	564	586	648	596
Exchange	6	5	13	10	17
Total	930	884	937	1,020	965
Revenues (per thousand cubic feet):					
Residential	$ 7.23	$ 6.86	$ 6.49	$ 6.68	$ 6.68
Commercial/Industrial	$ 1.95	$ 1.89	$ 2.14	$ 2.30	$ 2.51
Utility Electric Generation	$ 0.48	$ 0.50	$ 0.51	$ 0.45	$ 0.69
Wholesale	$ 0.49	$ 0.54	$ 0.48	$ 0.67	$ 0.79
Exchange	$ 0.17	$ 0.10	$ 0.06	$ 0.07	$ 0.22
Customers					
Active Meters (at end of period):					
Residential	4,624,279	4,582,553	4,526,150	4,483,324	4,459,250
Commercial	183,146	184,425	184,470	187,518	187,602
Industrial	22,642	22,952	22,976	23,505	23,924
Utility Electric Generation	8	9	8	8	8
Wholesale	4	3	3	3	3
Total	4,830,079	4,789,942	4,733,607	4,694,358	4,670,787
Residential Meter Usage (annual average):					
Revenues (dollars)	$ 375	$ 352	$ 345	$ 383	$ 371
Volumes (thousands of cubic feet)	51.9	50.5	53.2	57.4	55.6
System Usage (millions of cubic feet):					
Average Daily Sendout	2,515	2,452	2,579	2,795	2,611
Peak Day Sendout	3,887	4,000	4,120	4,350	4,578
Degree Days (2):					
Number	1,126(3)	1,195	1,241	1,459	1,203
Average (20 Year)	1,358	1,369	1,381	1,418	1,430
Percent of Average	82.9%	87.3%	89.9%	102.9%	84.1%
Population of Service Area (estimated at year end)	17,630,000	17,424,000	17,260,000	17,070,000	15,600,000

---

(1) Beginning January 1, 1994, rates included the ratepayer's portion of the Comprehensive Settlement (the amount included in rates for 1997, 1996, 1995, and 1994 was $98 million, $90 million, $84 million, and $119 million, respectively.)

(2) The number of degree days for any period of time indicates whether the temperature is relatively hot or cold. A degree day is recorded for each degree the average temperature for any day falls below 65 degrees Fahrenheit.

(3) Estimated calendar degree days.

SERVICE AREA

The Gas Company distributes natural gas throughout a 23,000-square-mile service territory with a population of approximately 17.6 million people. As indicated by the following map, its service territory includes most of southern California and part of central California.

[GRAPHIC-MAP OF SERVICE AREA]

Natural gas service is also provided on a wholesale basis to the distribution systems of the City of Long Beach, San Diego Gas & Electric Company and Southwest Gas Corporation.

UTILITY SERVICES

The Gas Company's customers are separated, for regulatory purposes, into core and noncore customers. Core customers are primarily residential and small commercial and industrial customers, without alternative fuel capability. There are approximately 4.8 million core customers (4.6 million residential and 200,000 small commercial and industrial). Noncore customers consist primarily of utility electric generation ("UEG"), wholesale and large commercial and industrial customers, and total approximately 1,600. Gas volumes delivered to UEG customers are greatly affected by the price and availability of electric power generated outside of The Gas Company's service area. UEG and other noncore customers are also sensitive to the price relationship between natural gas and alternate fuels, and many are capable of readily switching from one fuel to another, subject to air quality regulations.

The Gas Company offers two basic utility services, sale of gas and transportation of gas through two business units, one focusing on core distribution customers and the other on large volume gas transportation customers. Most residential customers and most other core customers purchase gas directly from The Gas Company. Noncore customers have the option of purchasing gas either from The Gas Company or from other sources (such as brokers or producers) for delivery through the Company's transmission and distribution system. Core customers are permitted to aggregate their gas requirements and also to purchase gas directly from brokers or producers, up to a limit of 10 % of the Company's core market. Most noncore customers procure their own gas supply rather than purchase from The Gas Company. Although the revenues from transportation throughput are less than for gas sales, The Gas Company generally earns the same margin whether the Company buys the gas and sells it to the customer or transports gas already owned by the customer. For 1998, approximately 88% of the total margin authorized is contributed by the core market, with 12% contributed by the noncore market. (See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations--Operating Results.")

The Gas Company continues to be obligated to purchase reliable supplies of natural gas to serve the requirements of its core customers. However, the only gas supplies that the Company may offer for sale to noncore customers are the same supplies that it purchases to serve its core customers.

The Gas Company also provides gas storage services for noncore and off-system customers on a bid and negotiated contract basis. The storage service program provides opportunities for customers to store gas on an "as available" basis, usually during the summer to reduce winter purchases when gas costs are generally higher. As of December 31, 1997, The Gas Company stored approximately 15 billion cubic feet of customer-owned gas.

DEMAND FOR GAS

Natural gas is a principal energy source in the Company's service area for residential, commercial and industrial uses as well as UEG requirements. Gas competes with electricity for residential and commercial cooking, water heating, space heating and clothes drying uses, and with other fuels for large industrial, commercial and UEG uses. Growth in The Gas Company's markets is largely dependent upon the health and expansion of the southern California economy. The Gas Company added approximately 43,700 new meters in 1997. This represents a growth rate of approximately 0.9%. The Gas Company anticipates that customer growth for 1998 will continue at about 1997 levels.

During 1997, approximately 97% of residential energy customers in The Gas Company service area used natural gas for water heating and 94% for space heating. Approximately 78% of those customers used natural gas for cooking and 72% for clothes drying.

Demand for natural gas by noncore customers such as large volume commercial, industrial and UEG customers is very sensitive to the price of alternative competitive fuels. These customers number only approximately 1,600; however, during 1997, accounted for approximately 15% of total gas revenues, 65% of total gas volumes delivered and 12% of the authorized gas margin. External factors such as weather, electric deregulation, the increased use of hydro-electric power, competing pipeline bypass and general economic conditions can result in significant shifts in this market. Demand for gas for UEG customer use is also greatly affected by the price and availability of electric power generated in other areas and purchased by the Company's UEG customers. (See "Competition" below.) Demand for gas for UEG customer use in 1997 increased as a result of higher demands for electricity and less availability of hydro-electricity. UEG customer demand decreased in 1996 as a result of abundant hydro-electricity.

As a result of electric industry restructuring, natural gas demand for electric generation within the Company's service area competes with electric power generated throughout the western United States. Effective March 31, 1998, California consumers are scheduled to be given the option of selecting their electric energy provider from a variety of local and out-of-state producers. The implementation of electric industry restructuring has no direct impact on the Company's operations. However, future volumes of natural gas transported for utility electric generation customers may be adversely affected to the extent that regulatory changes divert electricity generation from the Company's service area. In addition, the electric industry restructuring has mandated a 10% reduction of electric rates to core customers as of January 1, 1998; however, electricity is unlikely to overcome the entire cost advantage of natural gas for existing uses. (See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation--Factors Influencing Future Performance.")

COMPETITION

The Gas Company's throughput to enhanced oil recovery ("EOR") customers has decreased significantly since 1992 because of the bypass of the Company's system. The decrease in revenues from EOR customers is subject to full balancing account treatment, except for a 5% incentive to the Company, and therefore, does not have a material impact on earnings.

Bypass of other Company markets may also occur and the Company is fully at risk for reduction in such noncore volumes due to bypass. However, significant additional bypass would require construction of additional facilities by competing pipelines. The Gas Company is continuing to reduce its costs to maintain cost competitiveness to retain transportation customers.

To respond to bypass, the Company may seek expedited review of long-term gas transportation contracts with some noncore customers at lower than tariff rates. In addition, the Company allocates costs in a manner that eliminates subsidization of core customer rates by noncore customers. This allocation flexibility, together with negotiating authority, has enabled the Company to better compete with new interstate pipelines for noncore customers. In addition, under a capacity brokering program, for a fee, the Company provides to noncore customers, or others, a portion of its control of interstate pipeline capacity to allow more direct access to producers. Also, a comprehensive settlement of certain regulatory issues (the "Comprehensive Settlement") has improved the Company's competitiveness by reducing the cost of transportation service to noncore customers. (See "Item 7. Management's Discussion and Analysis of Financial Condition and Result of Operations--1995-1997 Financial Results.")

The Company's operations and those of its customers are affected by a growing number of environmental laws and regulations. These laws and regulations affect current operations as well as future expansion. Increasingly complex administrative and reporting requirements of environmental agencies applicable to commercial and industrial customers utilizing gas are not generally applicable to those using electricity. However, anticipated advancements in natural gas technologies should enable gas equipment to remain competitive with alternate energy sources.

SUPPLIES OF GAS

In 1997, The Gas Company delivered approximately 930 billion cubic feet ("Bcf") of natural gas through its system. Approximately 65% of these deliveries were customer-owned gas for which The Gas

Company provided transportation services. The balance of gas deliveries was gas purchased by The Gas Company and resold to customers.

Most of the natural gas delivered by The Gas Company is produced outside of California. These supplies are delivered to the Company's intrastate transmission system by interstate pipeline companies (primarily El Paso Natural Gas Company and Transwestern Natural Gas Company) that provide transportation services for supplies purchased from other sources by The Gas Company or its transportation customers. The rates that interstate pipeline companies may charge for gas and transportation services and other terms of service are regulated by the Federal Energy Regulatory Commission ("FERC").

Existing interstate pipeline capacity into California exceeds current demand by over 1 Bcf per day. This excess has reduced the market value of pipeline capacity well below FERC tariff rates. The Gas Company has exercised its step-down option on both the El Paso and Transwestern interstate pipeline systems, thereby reducing its firm interstate capacity obligations to 1.45 Bcf per day from 2.25 Bcf per day.

FERC-approved settlements have resulted in a reduction in the costs that The Gas Company may possibly have to pay for the capacity released back to El Paso and Transwestern that cannot be remarketed. Of the remaining 1.45 Bcf per day of capacity, the Company's core customers use 1.05 Bcf per day at the full FERC tariff rate. The remaining 0.4 Bcf per day of capacity is marketed at significant discounts. Under existing regulation in California, unsubscribed capacity costs associated with the remaining 0.4 Bcf per day are recoverable in customer rates. While including the unsubscribed pipeline cost in rates may impact the Company's ability to compete in highly contested markets, The Gas Company does not believe its inclusion will have a significant impact on volumes transported or sold.

The following table sets forth the sources of gas deliveries by The Gas Company from 1993 through 1997.

SOURCES OF GAS

	YEAR ENDED DECEMBER 31				
	1997	1996	1995	1994	1993
Gas Purchases (Billions of Cubic Feet):					
Market Gas	229	226	206	247	244
Affiliates	95	96	99	101	97
California Producers & Federal Offshore	5	12	29	36	28
Total Gas Purchases	329	334	334	384	369
Customer-Owned Gas and Exchange Receipts	614	518	620	658	622
Storage Withdrawal (Injection)--Net	(3)	42	(13)	(9)	(10)
Company Use and Unaccounted For	(10)	(10)	(4)	(13)	(16)
Net Gas Deliveries	930	884	937	1,020	965
Gas Purchases: (Thousands of dollars)					
Commodity Costs	$ 849	$ 627	$ 478	$ 644	$ 815
Fixed Charges*	250	276	264	368	398
Total Gas Purchases	$ 1,099	$ 903	$ 742	$ 1,012	$ 1,213
Average Cost of Gas Purchased (Dollars per Thousand Cubic Feet)**	$ 2.58	$ 1.88	$ 1.42	$ 1.68	$ 2.21

- ------------------------

* Fixed charges primarily include pipeline demand charges, take or pay settlement costs and other direct billed amounts allocated over the quantities delivered by the interstate pipelines serving the Company.

** The average commodity cost of gas purchased excludes fixed charges.

Market sensitive gas supplies (supplies purchased on the spot market as well as under longer-term contracts ranging from one month to ten years based on spot prices) accounted for approximately 70% of total gas volumes purchased by the Company during 1997, as compared with 68% and 62%, respectively, during 1996 and 1995. These supplies were generally purchased at prices significantly below those for other long-term sources of supply.

The Gas Company estimates that sufficient natural gas supplies will be available to meet the requirements of its customers well into the next century.

RATES AND REGULATION

The Gas Company is regulated by the California Public Utilities Commission ("CPUC"). The CPUC consists of five commissioners appointed by the Governor of California for staggered six-year terms. It is the responsibility of the CPUC to determine that utilities operate within the best interests of their customers and have the opportunity to earn a reasonable return on investment. The regulatory structure is complex and has a very substantial impact on the profitability of the Company.

PERFORMANCE BASED REGULATION

On July 16, 1997, the CPUC issued its final decision on The Gas Company's application for performance based regulation ("PBR"), which was filed with the CPUC in 1995.

For the five-year period that commenced January 1, 1998, PBR replaces the general rate case procedure and certain other regulatory proceedings. Under ratemaking procedures in effect prior to the PBR decision, The Gas Company typically filed a general rate case with the CPUC every three years. In a general rate case, the CPUC established a base margin, which is the amount of revenue to be collected from customers to recover authorized operating expenses (other than the cost of gas), depreciation, taxes and return on rate base.

Under PBR, regulators allow future income potential to be tied to achieving or exceeding specific performance and productivity measures, rather than relying solely on expanding utility rate base in a market where The Gas Company already has a highly developed infrastructure. Key elements of the PBR include a reduction in base rates, an indexing mechanism that limits future rate increases to the inflation rate less a productivity factor, a sharing mechanism with customers if earnings exceed the authorized rate of return on rate base, and rate refunds to customers if service quality deteriorates. The change in regulatory oversight changes the way earnings are affected by various factors. For example, under PBR earnings are more reliant on operational efficiencies and less on investment in property, plant and equipment.

PBR retains the balancing account mechanism by which The Gas Company refunds or collects in the future the difference between actual core revenue and the amounts authorized by the CPUC to be received in regulatory proceedings. Thus, full balancing account treatment allows the Company to fully recover amounts recorded as deferred costs or core revenue shortfalls, currently or in the future.

The Commission's PBR decision established the following rules for The Gas Company:

- The decision ordered a rate reduction to an initial base margin of $1.3 billion. This represents a rate reduction of $191 million effective August 1, 1997, partially offset by a $27 million rate increase to reflect inflation and customer growth effective on January 1, 1998.

- Earnings up to 25 basis points above the authorized rate of return are retained 100% by shareholders. Earnings that exceed the authorized rate of return on rate base by greater than 25 basis points are shared between customers and shareholders on a sliding scale that begins with 75% of earnings being given back to customers and declining to 0% as earned returns approach 300 basis points above authorized amounts. However, the decision rejected sharing of any amount by which actual earnings may fall below the authorized rate of return. In 1998, The Gas Company is authorized to earn a 9.49% return on rate base.

- Margin per customer is indexed based on inflation less an estimated productivity factor of 2.1% in the first year, increasing 0.1% per year to 2.5% in the fifth year. This factor includes 1% to approximate the projected impact of declining rate base.

- The CPUC decision allows for pricing flexibility for residential and small commercial customers, with any shortfalls being borne by shareholders and with gains shared between shareholders and customers.

The Gas Company implemented the base margin reduction on August 1, 1997, and implemented the remaining PBR elements on January 1, 1998. The CPUC intends for its PBR decision to be in effect for five years. The CPUC decision also provides the possibility that changes to the PBR mechanism could be adopted in a decision to be issued in the Company's 1998 Biennial Cost Allocation Proceeding ("BCAP") application anticipated to become effective on August 1, 1999.

The BCAP adjusts rates to reflect variances in core customer demand from estimates previously used in establishing core customer rates. The mechanism substantially eliminates the effect on core income of variances in core market demand and gas costs subject to the limitations of the Gas Cost Incentive Mechanism ("GCIM") and the Comprehensive Settlement. The BCAP will continue under PBR.

The GCIM compares the Company's cost of gas with the average market price of 30-day firm spot supplies delivered to The Gas Company service area. The mechanism permits full recovery of all costs within a "tolerance band" above the benchmark price and refunds all savings within a "tolerance band" below the benchmark price. The costs of purchases or savings outside the "tolerance band" are shared equally between customers and shareholders. The GCIM is authorized by the CPUC to be in effect through March 31, 1999.

In June 1997, the CPUC approved a $3.2 million pre-tax shareholder award for the GCIM year-ended March 31, 1996 which was recognized as income in 1997.

In June 1997, The Gas Company filed a GCIM application with the CPUC requesting a shareholder award for the annual period ending March 31, 1997. The CPUC is expected to issue a final decision on this matter by mid-1998, and income associated with this award will be recognized at that time.

AFFILIATE TRANSACTIONS

On December 16, 1997, the CPUC adopted rules establishing uniform standards of conduct governing the manner in which California investor-owned utilities conduct business with their affiliates providing energy or energy-related services within California. The objective of these rules, which are effective beginning January 1, 1998, is to ensure that the utilities' energy affiliates do not gain an unfair advantage over other competitors in the marketplace and that utility customers do not subsidize affiliate activities. (See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-- Factors Influencing Future Performance.")

ALLOWED RATE OF RETURN

For 1998, The Gas Company is authorized to earn a rate of return on rate base of 9.49% and a rate of return on common equity of 11.6%, which is unchanged from 1997.

GAS INDUSTRY RESTRUCTURING

The gas industry experienced an initial phase of restructuring during the 1980's by deregulating gas sales to noncore customers. On January 21, 1998, the CPUC released a staff report initiating a project to assess the current market and regulatory framework for California's natural gas industry. The general goals of the plan are to consider reforms to the current regulatory framework emphasizing market-oriented policies to benefit California natural gas consumers.

ENVIRONMENTAL MATTERS

The CPUC has approved a collaborative settlement which provides for rate recovery of 90% of environmental investigation and remediation costs without reasonableness review. In addition, The Gas Company has the opportunity to retain a portion of any insurance recovery to offset the 10% of costs not recovered in rates.

At December 31, 1997, the Company's estimated remaining liability for investigation and remediation was approximately $72 million, of which 90% is authorized to be recovered through the rate recovery mechanism described above. The estimated liability is subject to future adjustment pending further investigation. (See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation--Factors Influencing Future Performance.") Because of expected insurance and rate recovery, the Company believes that compliance with environmental laws and regulations will not have a material adverse effect on its consolidated results of operations or financial position.

The Gas Company has identified and reported to California environmental authorities 42 former gas manufacturing sites for which it (together with other utilities as to 21 of the sites) may have remedial obligations under environmental laws. As of December 31, 1997, ten of the sites have been remediated, of which seven have received certification from the California Environmental Protection Agency. Two sites are in the process of being remediated. Preliminary investigations, at a minimum, have been completed on 39 of the gas plant sites, including those sites at which the remediations described above have been completed. In addition, The Gas Company and its subsidiaries are one of a large number of major corporations that have been identified as potentially responsible parties for environmental remediation of two industrial waste disposal sites and two landfill sites.

EMPLOYEES

The Company employs approximately 6,615 persons. Most field, clerical and technical employees of the Company are represented by the Utility Workers' Union of America or the International Chemical Workers' Union. A contract on wages and working conditions is effective through March 31, 1999. Terms of the contract allow an extension through March 31, 2000.

MANAGEMENT

The executive officers of Southern California Gas Company are as follows:

NAME	AGE	POSITION	BECAME AN EXECUTIVE OFFICER
Warren I. Mitchell	60	President	August 1981
Neal E. Schmale	51	Executive Vice President and Chief Financial Officer	December 1997
Debra L. Reed	41	Senior Vice President	August 1988
Lee M. Stewart	52	Senior Vice President	November 1990
Paul J. Cardenas	51	Vice President	January 1995
Pamela J. Fair	39	Vice President	January 1995
Leslie E. LoBaugh, Jr.	52	Vice President and General Counsel	January 1995
Richard M. Morrow	48	Vice President	January 1995
Roy M. Rawlings	53	Vice President	January 1987
Anne S. Smith	44	Vice President	November 1991
George E. Strang	58	Vice President	July 1984
Ralph Todaro	47	Vice President and Controller	November 1988
Dennis V. Arriola	37	Vice President and Treasurer	August 1994

All of the Company's executive officers have been employed by the Company, the Parent, or its affiliates in management positions for more than the past five years, except for Mr. Schmale and Mr. Arriola. From 1992 until joining Pacific Enterprises in December 1997, Mr. Schmale was President of the Petroleum Products and Chemical Divisions of Unocal Corporation (1992-1994) and Chief Financial Officer of Unocal Corporation (1994-1997). From 1987 until joining the Company in August 1994, Mr. Arriola was a Vice President of Bank of America NT&SA (1992-1994) and a Vice President of Security Pacific National Bank (1987-1992).

Executive officers are elected annually and serve at the pleasure of the Board of Directors. There are no family relationships among any of the Company's executive officers.

ITEM 2. PROPERTIES

At December 31, 1997, The Gas Company owned approximately 2,843 miles of transmission and storage pipeline, 43,769 miles of distribution pipeline and 43,499 miles of service piping. It also owned 10 transmission compressor stations and 6 underground storage reservoirs (with a combined working storage capacity of approximately 116 Bcf and general office buildings, shops, service facilities, and certain other equipment necessary in the conduct of its business.

Southern California Gas Tower, a wholly-owned subsidiary of The Gas Company, has a 15% limited partnership interest in a 52-story office building in downtown Los Angeles. The Gas Company leases, and currently occupies about half of the building.

ITEM 3. LEGAL PROCEEDINGS

Except for the matters referred to in the financial statements filed with or incorporated by reference in Item 8 or referred to elsewhere in this Annual Report, neither the Company nor any of its subsidiaries is a party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted during the fourth quarter of 1997 to a vote of the Company's security holders.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Parent owns all of the Company's Common Stock. The information required by this item concerning dividends declared is included in the Statement of Consolidated Shareholders' Equity set forth in Item 8 of this Annual Report. Such information is incorporated herein by reference.

RANGE OF MARKET PRICES OF PREFERRED STOCK

	1997		1996	
	7 3/4%	6%-SERIES A	7 3/4%	6%-SERIES A
Three months ended:				
March 31	$25 3/4 - 25 1/4	$21 7/8 - 20 3/8	$26 1/8 - 25	$22 5/8 - 20 1/2
June 30	$25 3/4 - 25 1/4	$21 7/8 - 20 1/4	$25 3/4 - 25	$21 1/2 - 19 5/8
Sept. 30	$25 5/8 - 25 1/4	$23 - 21	$25 5/8 - 25 1/8	$21 1/4 - 20 1/8
Dec. 31	$25 3/4 - 24 7/8	$24 1/4 - 22 1/4	$25 3/4 - 25 1/4	$21 3/8 - 20

Market prices for the preferred stock were obtained from the Pacific Stock Exchange.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth certain selected financial data of the Company for 1993 through 1997.

SELECTED FINANCIAL DATA

	YEAR ENDED DECEMBER 31				
	1997	1996	1995	1994	1993
	(MILLIONS OF DOLLARS)				
Operating revenues	$ 2,641	$ 2,422	$ 2,279	$ 2,587	$ 2,811
Net income	$ 238	$ 201	$ 215	$ 191	$ 194
Total assets	$ 4,205	$ 4,354	$ 4,462	$ 4,776	$ 4,950
Long-term debt	$ 968	$ 1,090	$ 1,220	$ 1,397	$ 1,236

The Gas Company's parent, Pacific Enterprises, owns, as of the date hereof, approximately 99% of the voting stock, including all of the issued and outstanding common stock; therefore, per share data have been omitted.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

This section includes management's analysis of operating results from 1995 through 1997, and is intended to provide additional information about the Company's capital resources, liquidity and financial performance. This section also focuses on the major factors expected to influence future operating results and discusses future investment and financing plans. Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements.

The Parent and Enova Corporation ("Enova"), the parent company of San Diego Gas & Electric Company, have agreed to a business combination in which they will each become a subsidiary of a new holding company to be named Sempra Energy. The holders of the common stock of each company will become holders of the common stock of Sempra Energy. This strategic merger of equals will be a tax free transaction accounted for as a pooling of interests.

The combination was approved by the shareholders of both the Parent and Enova on March 11, 1997, but remains subject to approval by the California Public Utilities Commission ("CPUC") and the Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act of 1935. It also remains subject to final approval by the Federal Energy Regulatory Commission ("FERC"), which has conditionally approved the combination subject to the imposition of certain CPUC conditions that are expected to be imposed and are acceptable to the Parent and Enova.

A CPUC administrative law judge has issued a proposed decision recommending CPUC approval of the combination. The proposed decision also proposes that net savings from synergies and cost avoidances from the combination be shared between customers and shareholders over a five-year period, resulting in approximately $175 million for customers and $165 million for shareholders. A CPUC Commissioner has issued an alternate decision which proposes that the net savings (approximately $1 billion) be shared over a ten-year period approximately equally between customers and shareholders in essentially the same manner as originally proposed by the Parent and Enova. The Commissioner's alternate decision does not preclude other commissioners from proposing other alternate decisions. The CPUC final decision may be the proposed decision by the administrative law judge, the alternate decision proposed by the Commissioner, or another decision.

SEC and final FERC regulatory approvals for the combination are expected to be obtained following CPUC approval and the commencement of combined operations is expected during the summer of 1998.

In connection with the completion of the Department of Justice's review and clearance of the combination, Enova committed to follow through on its previously announced plans to auction off two fossil-fuel power plants. In addition, Sempra Energy agreed to obtain prior approval from the Department of Justice before acquiring or otherwise controlling any existing California generation facilities in excess of 500 megawatts.

CAPITAL RESOURCES AND LIQUIDITY

The Company's primary sources and uses of cash during the last three years are summarized in the following condensed statement of cash flows:

	YEAR ENDED DECEMBER 31		
SOURCES AND (USES) OF CASH	1997	1996	1995
	(DOLLARS IN MILLIONS)		
Operating Activities	$ 396	$ 638	$ 663
Capital Expenditures	(159)	(197)	(231)
Financing Activities:			
Issuance of Long-Term Debt	120	75	
Payments of Long-Term Debt	(242)	(153)	(168)
Redemption of Preferred Stock		(100)	
Short-Term Debt	89	28	(44)
Dividends	(258)	(259)	(242)
Total Financing Activities	(291)	(409)	(454)
Other	40	(31)	(23)
Increase (Decrease) in Cash and Cash Equivalents	$ (14)	$ 1	$ (45)

CASH FLOWS FROM OPERATING ACTIVITIES

The decrease in cash provided from operating activities to $396 million in 1997 from $638 million in 1996 is primarily due to greater working capital requirements in 1997. This was caused by actual gas costs incurred being higher than amounts collected in rates and resulted in undercollected regulatory balancing accounts at year-end 1997.

The decrease in cash provided from operating activities to $638 million in 1996 from $663 million in 1995 is primarily due to lower noncore revenues and lower amounts received from undercollected regulatory balancing accounts partially offset by the favorable settlement of gas contract issues.

There are a number of factors that impact the Company's cash flow from operations. These include changes in operating expenses and the authorized return on common equity.

CASH FLOWS FROM INVESTING ACTIVITIES

Capital expenditures primarily represent rate base investment at the Company. The table below summarizes capital expenditures by utility plant classification:

CAPITAL EXPENDITURES	1997	1996	1995
	YEAR ENDED DECEMBER 31 (DOLLARS IN MILLIONS)		
Distribution	$ 110	$ 124	$ 126
Transmission	14	24	19
Storage	10	5	19
Other	25	44	67
Total	$ 159	$ 197	$ 231

Capital expenditures for 1997 are $38 million lower than 1996, which is primarily related to the customer information system completed in early 1996 and other nonrecurring computer system expenditures in 1996.

Capital expenditures for 1996 are $34 million lower than 1995, which is primarily due to the completion in early 1996 of a new customer information system which increased the Company's responsiveness to customer needs and reduced operating costs and less capital required for repairs to earthquake-damaged storage facilities during 1995.

Capital expenditures are estimated to be approximately $180 million in 1998 and will be financed primarily by internally generated funds.

CASH FLOWS FROM FINANCING ACTIVITIES

Cash flow used for financing activities decreased $118 million in 1997 compared to 1996. The decrease was primarily due to the redemption of preferred stock in 1996.

Cash flow for financing activities decreased $45 million in 1996 compared to 1995. The decrease is due to an increase in long- and short-term debt partially offset by the redemption of preferred stock.

LONG-TERM DEBT

In 1997, cash was used for the repayment of $96 million of debt issued to finance the Comprehensive Settlement (see Note 3 of Notes to Consolidated Financial Statements) and repayment of $125 million First Mortgage Bonds. This was partially offset by the issuance of $120 million in Medium Term Notes and short-term borrowings used to finance working capital requirements.

In 1996, cash was used for a $67 million redemption of the Swiss Franc Bonds, and repayment of $79 million of debt issued to finance the Comprehensive Settlement. This was partially offset by cash provided from the issuance of $75 million in Medium Term Notes.

Cash was used in 1995 primarily for the repayment of short- and long-term debt, including $65 million of debt related to the Comprehensive Settlement.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents are $0, $14 million, and $13 million at December 31, 1997, 1996 and 1995, respectively. The Company anticipates that cash required in 1998 for capital expenditures, dividends and debt payments will be provided by cash generated from operating activities and existing cash balances.

In addition to cash from ongoing operations, the Parent and the Company have available certain multi-year credit agreements that provide backing for the Company's commercial paper program. At December 31, 1997, all bank lines of credit were unused. (For further discussion see Note 7 of Notes to Consolidated Financial Statements.)

COMPANY OPERATIONS

To fully understand the operations and financial results of the Company it is important to understand the ratemaking procedures that the Company is required to follow.

RATEMAKING PROCEDURES

The Company is regulated by the CPUC. It is the responsibility of the CPUC to determine that utilities operate in the best interest of their customers and have the opportunity to earn a reasonable return on investment.

On July 16, 1997, the CPUC issued its final decision on the Company's application for PBR, which was filed with the CPUC in 1995.

PBR replaces the general rate case procedure and certain other regulatory proceedings through December 31, 2002. Under ratemaking procedures in effect prior to the PBR decision, the Company typically filed a general rate case with the CPUC every three years. In a general rate case, the CPUC established a base margin, which is the amount of revenue to be collected from customers to recover authorized operating expenses (other than the cost of gas), depreciation, taxes and return on rate base.

Under PBR, regulators allow future income potential to be tied to achieving or exceeding specific performance and productivity measures, rather than relying solely on expanding utility rate base in a market where the Company already has a highly developed infrastructure. Key elements of the PBR include a reduction in base rates, an indexing mechanism that limits future rate increases to the inflation rate less a productivity factor, a sharing mechanism with customers if earnings exceed the authorized rate of return on rate base and rate refunds to customers if service quality deteriorates. The change in regulatory oversight changes the way earnings are affected by various factors. For example, under PBR earnings are more dependent on operational efficiencies and less on investment in property, plant and equipment.

PBR retains the balancing account mechanism by which the Company refunds or collects in the future the difference between actual core revenue and the amounts authorized by the CPUC to be received in a rate case or other regulatory proceedings. Thus, full balancing account treatment allows the Company to fully recover amounts recorded as deferred costs or core revenue shortfalls, currently or in the future.

The Commission's PBR decision established the following rules for the Company:

- The decision ordered a net rate reduction of $164 million to an initial base margin of $1.3 billion. The $164 million is comprised of a rate reduction of $191 million, effective August 1, 1997, partially offset by a $27 million rate increase to reflect inflation and customer growth effective on January 1, 1998.

- Earnings up to 25 basis points exceeding the authorized rate of return on rate base are retained 100% by shareholders. Earnings that exceed the authorized rate of return on rate base by greater than 25 basis points are shared between customers and shareholders on a sliding scale that begins with 75% of earnings being given back to customers and declining to 0% as earned returns approach 300 basis points above authorized amounts. However, the decision rejects sharing of any amount by which actual earnings may fall below the authorized rate of return. In 1998, the Company is authorized to earn a 9.49% return on rate base.

- Revenue or margin per customer is indexed based on inflation less an estimated productivity factor of 2.1% in the first year, increasing 0.1% per year up to 2.5% in the fifth year. This factor includes 1% to approximate the projected impact of declining rate base.

- The CPUC decision allows for pricing flexibility for residential and small commercial customers, with any shortfalls being borne by shareholders and with gains shared between shareholders and ratepayers.

- The decision allows the Company to continue offering some types of products and services it currently offers (e.g. contract meter reading), but the issue of other new product and service offerings was addressed in the CPUC's Affiliate Transaction Decision. For further discussion see Note 3 of Notes to Consolidated Financial Statements.

The Company implemented the base margin reduction on August 1, 1997, and implemented the remaining PBR elements on January 1, 1998. The CPUC intends for its PBR decision to be in effect for five years. The CPUC decision also provides the possibility that changes to the PBR mechanism could be adopted in a decision to be issued in the Company's 1998 Biennial Cost Allocation Proceeding (BCAP) application anticipated to become effective on August 1, 1999.

BCAP adjusts rates to reflect variances in core customer demand from estimates adopted previously. The mechanism substantially eliminates the effect on core income of variances in core market demand and gas costs subject to the limitations of the Gas Cost Incentive Mechanism (GCIM) and the Comprehensive Settlement. BCAP will continue under PBR. For further discussion, see Note 3 of Notes to Consolidated Financial Statements.

The GCIM compares the Company's cost of gas with the average market price of 30-day firm spot supplies delivered to the Company's service area. The mechanism permits full recovery of all costs within a "tolerance band" above and below the benchmark price and refunds all savings within a "tolerance band" below the benchmark price. The costs of purchases or savings outside the "tolerance band" are shared equally between customers and shareholders. The GCIM is authorized by the CPUC to be in effect through March 31, 1999.

In June 1997, the CPUC approved a $3.2 million pre-tax shareholder award for the GCIM year ended March 31, 1996, which was recognized as income in 1997. Also in June 1997, the Company filed an application with the CPUC requesting a shareholder award for the annual period ending March 31, 1997. The CPUC is expected to issue a final decision on this matter by mid-1998, and income associated with this award will be recognized at that time.

1995 - 1997 FINANCIAL RESULTS

Key financial and operating data for the Company are highlighted in the table below.

	YEAR ENDED DECEMBER 31		
	1997	1996	1995
	(DOLLARS IN MILLIONS)		
Operating revenues	$ 2,641	$ 2,422	$ 2,279
Cost of gas distributed	$ 1,088	$ 923	$ 737
Operation and maintenance	$ 712	$ 725	$ 760
Net income (after preferred dividends)	$ 231	$ 193	$ 203
Authorized return on rate base	9.49%	9.42%	9.67%
Authorized return on common equity	11.60%	11.60%	12.00%
Weighted average rate base	$ 2,734	$ 2,777	$ 2,766

1997 COMPARED TO 1996. The Company's operating revenues increased $219 million in 1997 compared to 1996 primarily due to an increase in the average unit cost of gas which is recoverable in rates. To a lesser extent, the increase was also due to increased throughput to UEG customers due to increased demand for electricity.

The Company's cost of gas distributed increased $165 million in 1997 compared to 1996 largely due to an increase in the average commodity cost of gas purchased by the Company, excluding fixed pipeline charges, to $2.58 per thousand cubic feet compared to $1.88 per thousand cubic feet in 1996.

The Company's operation and maintenance expenses decreased $13 million in 1997 compared to 1996 because of its continued emphasis on reducing costs. The extent of this reduction was partially offset by reduced costs in 1996 from favorable litigation settlements.

Net income increased $38 million in 1997 compared to 1996 primarily due to increased throughput to UEG customers, lower operation and maintenance expenses than amounts authorized in rates, and a nonrecurring non-cash charge of $26.6 million, after-tax, in 1996 partially offset by a lower margin established in the PBR decision. The non-cash charge of $26.6 million in 1996 was the result of continuing developments in the CPUC's restructuring of the electricity utility industry. The charge was needed because the Company anticipated that throughput to noncore UEG customers would be below the levels projected in 1993 at the time of the Comprehensive Settlement (See Note 3 of Notes to Consolidated Financial Statements). Consequently, the Company believed it would not realize the remaining revenue enhancements that were applied to offset the costs of the Comprehensive Settlement. In connection with the 1992 quasi-reorganization, the Parent established a liability for this issue and therefore this charge had no effect on Pacific Enterprises' consolidated net income.

1996 COMPARED TO 1995. The Company's operating revenues increased $143 million in 1996 compared to 1995 primarily due to an increase in the average unit cost of gas. Gas costs are recoverable in revenues subject to the GCIM. The increase in revenue was also generated by demand from refinery customers who required 21 Bcf more gas in 1996 than in 1995. The increase in revenue was partially offset by a decrease in UEG revenues due to a reduction in volumes transported because of abundant inexpensive hydro-electricity.

The Company's cost of gas distributed increased $186 million in 1996 due primarily to an increase in the average unit cost of gas. The average commodity cost of gas purchased by the Company, excluding fixed charges for 1996, was $1.88 per thousand cubic feet, compared to $1.42 per thousand cubic feet in 1995.

The Company's operation and maintenance expenses decreased $35 million in 1996 compared to 1995. The decrease primarily reflects savings resulting from the Company's continued improvements in efficiency and management's close control of expenses and nonrecurring favorable settlements, totaling $28 million. One settlement was from gas producers for damages incurred to customer and company equipment as a result of impure gas supplies, and the other reflects the resolution of certain environmental insurance claims.

Net income (after preferred dividends) was $193 million in 1996 compared to $203 million in 1995. The decline in the Company's earnings was primarily due to a nonrecurring non-cash charge of $26.6 million, partially offset by the effects of the nonrecurring favorable settlements and lower operating costs.

ACHIEVED AND AUTHORIZED RATE OF RETURN. The Company has achieved or exceeded the rate of return on rate base authorized by the CPUC for 15 consecutive years. In 1997, the Company achieved a 11.62% return on rate base compared to a 9.49% authorized return and a 16.74% return on equity compared to a 11.60% authorized return. The improved returns were primarily due to lower operating costs as a result of increased operating efficiencies.

In 1996, the Company achieved a 10.31% return on rate base compared to a 9.42% authorized return and a 13.59% return on equity compared to a 11.60% authorized return. The improved returns were primarily due to lower operating costs as a result of increased operating efficiencies and the favorable settlements.

The Company plans to continue efforts to control costs in 1998. In 1998, the Company is authorized to earn 9.49% return on rate base and 11.60% on common equity, which is unchanged from 1997.

OPERATING RESULTS

The table below summarizes the components of the Company's throughput and rates charged to customers for the past three years. Rates include the customer portion of the Comprehensive Settlement (See Note 3 of Notes to Consolidated Financial Statements.) The amount included in rates for 1997, 1996 and 1995 were $98 million, $90 million and $84 million, respectively.

	GAS SALES		TRANSPORTATION AND EXCHANGE		TOTAL	
	THROUGHPUT	REVENUE	THROUGHPUT	REVENUE	THROUGHPUT	REVENUE
	(DOLLARS IN MILLIONS, VOLUMES IN BILLION CUBIC FEET)					
1997:						
Residential	237	$1,726	3	$ 10	240	$1,736
Commercial/Industrial	80	502	314	255	394	757
Utility Electric Generation			158	76	158	76
Wholesale			138	67	138	67
Total in Rates	317	$2,228	613	$ 408	930	2,636
Balancing and Other						5
Total Operating Revenues						$2,641
1996:						
Residential	233	$1,603	3	$ 10	236	$1,613
Commercial/Industrial	82	473	297	236	379	709
Utility Electric Generation			139	70	139	70
Wholesale			130	70	130	70
Total in Rates	315	$2,076	569	$ 386	884	2,462
Balancing and Other						(40)
Total Operating Revenues						$2,422
1995:						
Residential	237	$1,547	2	$ 7	239	$1,554
Commercial/Industrial	97	546	267	206	364	752
Utility Electric Generation			205	104	205	104
Wholesale	4	7	125	55	129	62
Total in Rates	338	$2,100	599	$ 372	937	2,472
Balancing and Other						(193)
Total Operating Revenues						$2,279

Although the revenues from transportation throughput are less than for gas sales, the Company generally earns the same margin whether it buys the gas and sells it to the customer or transports gas already owned by the customer. Throughput, the total gas sales and transportation volumes moved through the Company's system, increased in 1997 compared to 1996, primarily because of higher demand for electricity from gas-fired electric generation and less availability of hydro-electricity. The decrease in throughput in 1996 compared to 1995 was a result of abundant inexpensive hydro-electricity resulting from high levels of precipitation last winter reducing the gas demands of UEG customers.

FACTORS INFLUENCING FUTURE FINANCIAL PERFORMANCE

Because of the ratemaking and regulatory process, electric and gas industry restructurings and the changing energy marketplace, there are several factors that will influence future financial performance of the Company. These factors are summarized below.

PERFORMANCE BASED REGULATION. PBR became effective on January 1, 1998, except for a base margin reduction of $191 million which was effective August 1, 1997. Under PBR, regulators allow future income potential to be tied to achieving or exceeding specific performance and productivity measures, rather than relying solely on expanding utility rate base. The Company continues to meet all criteria for continued application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation." See Note 2 of Notes to Consolidated Financial Statements.

AFFILIATE TRANSACTION DECISION. On December 16, 1997, the CPUC adopted rules establishing uniform standards of conduct governing the manner in which California investor-owned utilities conduct business with their affiliates providing energy or energy-related services within California. The objective of these rules, which were effective January 1, 1998, is to ensure that the utilities' energy affiliates do not gain an unfair advantage over other competitors in the marketplace and that utility customers do not subsidize affiliate activities. For further discussion of the key elements of the CPUC decision, see Note 3 of the Notes to Consolidated Financial Statements.

Utility-to-utility transactions are also included under the definition of an affiliate transaction unless the rules are modified in a subsequent merger or other regulatory proceeding. On January 23, 1998, at the request of the Administrative Law Judge presiding over the Parent/Enova merger proceeding, the Parent and Enova jointly filed their comments regarding the impact of the Affiliate Transaction Decision on the original estimate of merger synergy savings. The filing indicated that the Affiliate Transaction rules, if applied to utility-to-utility transactions, would significantly reduce the anticipated synergy savings previously discussed in the "Introduction." The CPUC will consider this issue as part of the Parent/Enova merger proceeding.

ALLOWED RATE OF RETURN. For 1998, the Company is authorized to earn a rate of return on rate base of 9.49% and a rate of return on common equity of 11.6%, which is unchanged from 1997.

MANAGEMENT CONTROL OF EXPENSES AND INVESTMENT. Over the past 15 years, management has been able to control operating expenses and investment within the amounts authorized to be collected in rates.

It is the intent of management to control operating expenses and investment within the amounts authorized to be collected in rates in the PBR decision. The Company intends to make the efficiency improvements, changes in operations and cost reductions necessary to achieve this objective and earn its authorized rate of return. However, in view of the earnings sharing mechanism and other elements of the PBR authorized by the CPUC, it will be more difficult for the Company to achieve returns in excess of authorized returns at levels that it has experienced in 1997 and other recent years.

ELECTRIC INDUSTRY RESTRUCTURING. As a result of electric industry restructuring, natural gas-generated electricity within the Company's service area competes vigorously with electric power generated throughout the western United States.

Effective March 31, 1998, California consumers are scheduled to be given the option of selecting their electric energy provider from a variety of local and out-of-state producers. The implementation of electric industry restructuring has no direct impact on the Company's operations. However, future volumes of natural gas transported for current utility electric generation customers may be adversely affected to the extent these regulatory changes divert electricity generated from the Company's service territory. In addition, the electric industry restructuring has set a mandated 10% reduction of electric rates to core customers as of January 1, 1998; however, electricity is unlikely to overcome the entire cost advantage of natural gas for existing uses.

The Company has considered the effect of Statement of Financial Accounting Standard No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" on the Company's financial statements, including the potential effect of electric industry restructuring. Although the Company believes that the volume of gas transported by the Company may be adversely impacted by electric industry restructuring, it is not anticipated to result in an impairment of assets as defined in SFAS 121, because the expected undiscounted future cash flows from the Company's investment in its gas transportation infrastructure is greater than its carrying amount.

GAS INDUSTRY RESTRUCTURING. The gas industry experienced an initial phase of restructuring during the 1980's by deregulating gas sales to noncore customers. On January 21, 1998, the CPUC released a staff report initiating a project to assess the current market and regulatory framework for California's natural gas industry. The general goals of the plan are to consider reforms to the current regulatory framework emphasizing market-oriented policies benefiting California natural gas consumers.

NONCORE BYPASS. The Company's throughput to enhanced oil recovery (EOR) customers in the Kern County area has decreased significantly since 1992 because of the bypass of the Company's system by competing interstate pipelines. The decrease in revenues from EOR customers did not have a material impact on the Company's earnings.

Bypass of other markets also may occur, and the Company is fully at risk for a reduction in non-EOR, noncore volumes due to bypass. However, significant additional bypass would require construction of additional facilities by competing pipelines. The Company is continuing to reduce its costs to maintain cost competitiveness to retain transportation customers.

NONCORE PRICING. To respond to bypass, the Company has received authorization from the CPUC for expedited review of long-term gas transportation service contracts with some noncore customers at lower than tariff rates. In addition, the CPUC approved changes in the methodology that eliminates subsidization of core customer rates by noncore customers. This allocation flexibility, together with negotiating authority, has enabled the Company to better compete with new interstate pipelines for noncore customers.

NONCORE THROUGHPUT. The Company's earnings may be adversely impacted if gas throughput to its noncore customers varies from estimates adopted by the CPUC in establishing rates. There is a continuing risk that an unfavorable variance in noncore volumes may result from external factors such as weather, electric deregulation, the increased use of hydro-electric power, competing pipeline bypass of the Company's system and a downturn in general economic conditions. In addition, many noncore customers are especially sensitive to the price relationship between natural gas and alternate fuels, as they are capable of readily switching from one fuel to another, subject to air quality regulations. The Company is at risk for the lost revenue.

Through July 31, 1999 any favorable earnings effect of higher revenues resulting from higher throughput to noncore customers has been limited as a result of the Comprehensive Settlement (see Note 3 of Notes to Consolidated Financial Statements).

EXCESS INTERSTATE PIPELINE CAPACITY. Existing interstate pipeline capacity into California exceeds current demand by over one Bcf per day. This situation has reduced the market value of the capacity well below the Federal Energy Regulatory Commission's ("FERC") tariffs. The Company has exercised its step-down option on both the El Paso and Transwestern systems, thereby reducing its firm interstate capacity obligation from 2.25 Bcf per day to 1.45 Bcf per day.

FERC-approved settlements have resulted in a reduction in the costs that the Company may have possibly been required to pay for the capacity released back to El Paso and Transwestern that cannot be remarketed. Of the remaining 1.45 Bcf per day of capacity, the Company's core customers use 1.05 Bcf per day at the full FERC tariff rate. The remaining 0.4 Bcf per day of capacity is marketed at significant discounts. Under existing regulation in California, unsubscribed capacity costs associated with the remaining 0.4 Bcf per day are recoverable in customer rates. While including the unsubscribed pipeline cost in rates may impact the Company's ability to compete in highly contested markets, the Company does not believe its inclusion will have a significant impact on volumes transported or sold.

ENVIRONMENTAL MATTERS. The Company's operations and those of its customers are affected by a growing number of environmental laws and regulations. These laws and regulations affect current operations as well as future expansion. Increasingly complex administrative and reporting requirements of environmental agencies applicable to commercial and industrial customers utilizing natural gas are not generally required by those using electricity. However, anticipated advancements in natural gas technologies are expected to enable gas equipment to remain competitive with alternate energy sources. Environmental laws also require cleanup of facilities no longer in use. Because of current and expected rate recovery, the Company believes that compliance with these laws will not have a significant impact on its financial statements. For further discussion of environmental matters, see Note 5 of Notes to Consolidated Financial Statements.

UNION CONTRACT. Most field, clerical and technical employees of the Company are represented by the Utilities Workers' Union of America or the International Chemical Workers' Union. The existing contract with these employees on wages and working conditions will expire on March 31, 1999. Terms of the contract allow an extension through March 31, 2000.

CALIFORNIA ECONOMY. Growth in the Company's markets is largely dependent on the health and expansion of the southern California economy. The Company added approximately 43,700 new meters in 1997. This represents a growth rate of approximately 0.9%. The Company anticipates that customer growth will continue at 1997 levels. Southern California has finally emerged from its prolonged recession and job growth in 1997 was stronger than the U.S. average.

OTHER INCOME AND INTEREST EXPENSE

OTHER INCOME AND DEDUCTIONS. Other income-net, which primarily consists of interest income from short-term investments and interest income on regulatory accounts receivable balances, was $7 million, $1 million and $6 million in 1997, 1996 and 1995, respectively. The increase from 1996 is primarily due to higher interest income on regulatory accounts receivable balances in 1997. The decrease from 1995 is primarily due to unusually high short-term investments in 1995, as a result of overcollected gas costs that were refunded to customers in the fourth quarter of 1995. This was partially offset by higher interest income on regulatory accounts receivable balances in 1996 compared to 1995. Other-net expense consists primarily of contributions and amortization of loss on reacquired debt.

INTEREST EXPENSE. Interest expense was $87 million, $86 million and $91 million in 1997, 1996 and 1995, respectively. Interest expense for 1997 increased only slightly compared to 1996. Interest expense in 1996 was reduced from the 1995 level as a result of the lower long-term debt balance maintained throughout the year, the redemption of $67 million Swiss Franc bonds and refinancing of Company debt at lower interest rates.

RISK MANAGEMENT

Market risk generally represents the risk of loss that may result from the potential change in the value of a financial instrument as a result of fluctuations in interest and currency exchange rates and equity and commodity prices. Market risk is inherent to both derivative and non-derivative financial instruments. The following is a discussion of the Company's primary market risk exposures as of December 31, 1997, including a discussion of how these exposures are managed.

INTEREST RATE RISK. The Company has historically funded its operations through long-term bond issues with fixed interest rates. With the restructuring of the regulatory process, greater flexibility has been permitted within the debt management process. As a result, recent debt offerings have been selected with short-term maturities. The Company also evaluates the use of a combination of fixed and floating rate debt. Interest rate swaps, subject to regulatory constraints, may be used to adjust interest rate exposures when appropriate, based upon market conditions.

A portion of the Company's borrowings are denominated in foreign currencies, which exposes the Company to market risk associated with exchange rate movements. The Company's policy generally is to hedge major foreign currency cash exposures through swap transactions. These contracts are entered into with major international banks thereby minimizing the risk of credit loss.

The Company employes a variance/covariance approach in its calculation of Value at Risk (VaR), which measures the potential losses in fair value or earnings that could arise from changes in market conditions, using a 95% confidence level and assuming a one-year holding period. VaR is a statistical measure that takes into consideration historical volatilities and correlations of market data (i.e., interest rates and currency exchange rates). The VaR, which is the potential loss in fair value of long-term debt sensitive to changes in interest rates, is estimated at $116 million as of December 31, 1997. The total VaR is attributable to debt obligations with fixed interest rates. The VaR attributable to currency exchange rates nets to zero as a result of a currency swap which is directly matched to the Company's Swiss Franc debt obligation.

NATURAL GAS PRICE RISK. The Company is subject to price risk on its natural gas purchases if its cost exceeds a 2% tolerance band above the GCIM benchmark price. Price risk is influenced by physical contract positions, financial contract positions, basis risk, system demand, and regulation. The Company becomes subject to price risk when positions are incurred during the buying, selling, and storage of natural gas.

A Gas Acquisition Committee, composed of officers of the Company and Pacific Enterprises, is responsible for establishing natural gas price risk management objectives and strategies that are consistent with the Price Risk Management Policy. The Committee also monitors results of all natural gas purchasing activities to ensure that such activities are effective and conducted in a manner consistent with approved policies and procedures.

As part of the Price Risk Management Policy, the Company has established fixed price and basis position limits. Volumetric limits define the maximum position exposure each management level within the Company is authorized to accept without obtaining higher approval.

In addition to the position limits, internal controls are in place to set individual contract limits, monitor established credit limits, require current reporting of trading activities and ensure proper segregation of duties.

The Company monitors and controls credit exposure through a credit approval process and the assignment and monitoring of credit limits. Credit exposure is defined as the "balance owed" to the Company on current market valuation. Credit exposure represents the positive contract value that might be forfeited in the event of counterparty default. Credit exposure is computed on a daily mark-to-market basis. The current credit exposure and credit limit of each supplier is monitored on an ongoing basis and reported weekly to the Company's management and the Parent's Treasury Department.

The VaR methodology employed by the Company with respect to natural gas price risk is applied to physical, as well as financial, natural gas positions. The methodology involves determining the fair value impact of the maximum expected adverse price change for the aggregate net position in each forward month, using a 95% confidence level and assuming a one month holding period. The value derived for each forward month is then aggregated to arrive at the total VaR. In making these calculations, volatilities are based upon the respective forward month's implied volatility derived from quoted option prices. As of December 31, 1997, the total VaR of the Company's natural gas positions was not material to the Company's financial position.

YEAR 2000

In 1997, the Company began a multi-year project to modify its computer systems as necessary to ensure continued effective operations in the year 2000 and beyond. The initial focus of the project is on the systems key to customer safety, gas operations, external reporting, and billing and collection processes. The project is expected to be completed in the spring of 1999. During 1997, the Company incurred expenses of $10 million on the project, and expects to spend approximately $27 million over the life of the project. An assessment of the readiness of external entities which the Company interfaces with, such as vendors, customers and others, is ongoing.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information required by this item is set forth under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations--Risk Management."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

STATEMENT OF CONSOLIDATED INCOME

	YEAR ENDED DECEMBER 31		
	1997	1996	1995
	(DOLLARS IN MILLIONS)		
OPERATING REVENUES	$ 2,641	$ 2,422	$ 2,279
OPERATING EXPENSES			
Cost of Gas Distributed	1,088	923	737
Operation	640	643	673
Maintenance	72	82	87
Depreciation	251	248	237
Income Taxes	174	145	151
Local Franchise Payments	36	34	34
Ad Valorem Taxes	35	35	34
Payroll and Other Taxes	27	26	26
Total	2,323	2,136	1,979
Net operating revenue	318	286	300
OTHER INCOME AND (DEDUCTIONS)			
Interest Income	1	1	8
Regulatory Interest	15	4	1
Allowance for Equity Funds Used During Construction	2	4	5
Income Taxes on Non-Operating Income	(4)	(3)	
Other--Net	(7)	(5)	(8)
Total	7	1	6
INTEREST CHARGES AND (CREDITS)			
Interest on Long-Term Debt	82	80	87
Other Interest	6	8	7
Allowance for Borrowed Funds Used During Construction	(1)	(2)	(3)
Total	87	86	91
Net Income	238	201	215
Dividends on Preferred Stock	7	8	12
Net Income Applicable to Common Stock	$ 231	$ 193	$ 203

See Notes To Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

	DECEMBER 31 1997	DECEMBER 31 1996
	(DOLLARS IN MILLIONS)	
ASSETS		
Utility Plant--at original cost	$ 5,978	$ 5,963
Less: Accumulated Depreciation	2,904	2,795
Utility plant--net	3,074	3,168
Current Assets:		
Cash and cash equivalents		14
Accounts receivable--trade (less allowance for doubtful receivables of $17 in 1997 and $16 in 1996)	499	413
Regulatory accounts receivable--net	355	296
Income taxes receivable		11
Deferred income taxes	11	22
Gas in storage	25	28
Materials and supplies	13	13
Prepaid expenses	14	13
Total current assets	917	810
Regulatory Assets	214	376
Total	$ 4,205	$ 4,354
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common equity:		
Common stock	$ 835	$ 835
Retained earnings	535	555
Total common equity	1,370	1,390
Preferred stock	97	97
Long-term debt	968	1,090
Total capitalization	2,435	2,577
Current Liabilities:		
Short-term debt	351	262
Accounts payable--trade	119	178
Accounts payable--affiliates	30	44
Accounts payable--other	268	296
Other taxes payable	30	28
Accrued income taxes	39	
Long-term debt due within one year	147	147
Accrued interest	52	41
Other accrued liabilities	78	63
Total current liabilities	1,114	1,059
Customer Advances for Construction	34	42
Deferred Income Taxes	373	405
Deferred Investment Tax Credits	61	64
Other Deferred Credits	188	207
Commitments and Contingent Liabilities (Note 5)		
Total	$ 4,205	$ 4,354

See Notes To Consolidated Financial Statements.

STATEMENT OF CONSOLIDATED CASH FLOWS

	YEAR ENDED DECEMBER 31		
	1997	1996	1995
	(DOLLARS IN MILLIONS)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 238	$ 201	$ 215
Items Not Requiring Cash:			
Depreciation	251	248	237
Deferred income taxes	(15)	15	60
Deferred investment tax credits	(3)	(3)	(3)
Allowance for funds used during construction	(4)	(6)	(9)
Other	(21)	24	53
Net Change in Other Working Capital Components:			
Accounts receivable	(86)	(14)	125
Regulatory accounts receivable	36	50	184
Gas in storage	3	27	9
Other current assets	(1)	20	13
Accounts payable	(101)	90	(16)
Other taxes payable	51	(18)	(72)
Deferred income taxes	21	(6)	(76)
Other current liabilities	27	10	(57)
Net cash provided by operating activities	396	638	663
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital Expenditures for Utility Plant	(159)	(197)	(231)
(Increase) Decrease in Other Assets--Net	40	(31)	(23)
Net cash used in investing activities	(119)	(228)	(254)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Dividends	(258)	(259)	(242)
Issuance of Long-Term Debt	120	75	
Payments of Long-Term Debt	(242)	(153)	(168)
Redemption of Preferred Stock		(100)	
Increase (Decrease) in Short-Term Debt	89	28	(44)
Net cash used in financing activities	(291)	(409)	(454)
Increase (Decrease) in Cash and Cash Equivalents	(14)	1	(45)
Cash and Cash Equivalents--January 1	14	13	58
Cash and Cash Equivalents--December 31	$	$ 14	$ 13
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash Paid During the Year for:			
Interest (net of amount capitalized)	$ 75	$ 85	$ 82
Income taxes	$ 132	$ 127	$ 232

See Notes To Consolidated Financial Statements.

STATEMENT OF CONSOLIDATED SHAREHOLDERS' EQUITY

	PREFERRED STOCK	COMMON STOCK	RETAINED EARNINGS
	(DOLLARS IN MILLIONS)		
BALANCE AT DECEMBER 31, 1994	$ 197	$ 835	$ 643
Net Income			215
Cash Dividends Declared:			
Preferred stock			(12)
Common stock			(233)
BALANCE AT DECEMBER 31, 1995	197	835	613
Net Income			201
Cash Dividends Declared:			
Preferred stock			(8)
Common stock			(251)
Preferred Stock Redeemed (1000 shares)	(100)		
BALANCE AT DECEMBER 31, 1996	97	835	555
Net Income			238
Cash Dividends Declared:			
Preferred stock			(7)
Common stock			(251)
BALANCE AT DECEMBER 31, 1997	$ 97	$ 835	$ 535

The number of shares of preferred stock and common stock authorized and outstanding at December 31, 1997 and 1996, is set forth in Note 10 of Notes to Consolidated Financial Statements.

See Notes To Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. MERGER AGREEMENT WITH ENOVA CORPORATION

On October 14, 1996, Pacific Enterprises (Parent) and Enova Corporation (Enova), the parent company of San Diego Gas & Electric (SDG&E), announced an agreement, which both Boards of Directors unanimously approved, for the combination of the two companies in a tax-free, strategic merger of equals to be accounted for as a pooling of interests. The combination was approved by the shareholders of both companies on March 11, 1997. On December 16, 1997, the Parent and Enova announced that the name of the new company will be Sempra Energy.

As a result of the combination, the Parent and Enova will become subsidiaries of Sempra Energy and their common shareholders will become common shareholders of the new holding company. Pacific Enterprises' common shareholders will receive 1.5038 shares of Sempra Energy's common stock for each share of the Parent's common stock, and Enova common shareholders will receive one share of Sempra Energy's common stock for each share of Enova common stock. Preferred stock of Pacific Enterprises, SoCalGas, and SDG&E will remain outstanding.

The merger is subject to approval by certain governmental and regulatory agencies including the California Public Utilities Commission (CPUC), the Securities and Exchange Commission and Federal Energy Regulatory Commission (FERC) and the expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act. Approval of the merger and commencement of operations is expected to occur during the summer of 1998.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Southern California Gas Company (the Company) is a subsidiary of Pacific Enterprises. The Parent owns approximately 96% of the Company's voting stock, including all of its issued and outstanding common stock; therefore, per share data have been omitted.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. One subsidiary has a 15% limited partnership interest in a 52-story office building in which the Company occupies approximately one-half of the leasable space. Investments in 50% or less joint ventures and partnerships are accounted for by the equity or cost method, as appropriate.

RECLASSIFICATIONS

Certain changes in account classification have been made in the prior years' consolidated financial statements to conform to the 1997 financial statement presentation.

REGULATION

In conformity with generally accepted accounting principles (GAAP), the Company's accounting policies reflect the financial effects of rate regulation authorized by the CPUC. The Company applies the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation." This statement requires cost-based rate regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. The Company records Regulatory Assets which represent assets which are being recovered through customer rates or are probable of being recovered through customer rates. As of December 31, 1997, the Company had $214 million of regulatory assets which included the following: costs of reacquiring debt--$43 million; deferred income taxes--$66 million (see Note 4); environmental remediation--$72 million (see Note 5); and other costs--$33 million. Maintenance of the regulatory accounts and regulatory accounts receivable represents the only difference in the application of GAAP for the Company versus non-regulated entities.

REGULATORY ACCOUNTS RECEIVABLE--NET

Authorized regulatory balancing accounts are maintained to accumulate undercollections and overcollections from the revenue and cost estimates adopted by the CPUC in setting rates. The Company makes periodic filings with the CPUC to adjust future gas rates to account for such variances.

GAS IN STORAGE

Gas in storage inventory is stated at last-in, first-out cost. As a result of a regulatory accounting procedure, the pricing of gas in storage does not have any effect on net income. If the first-in, first-out method of accounting for gas in storage inventory had been used by the Company, inventory would have been higher than reported at December 31, 1997 and 1996 by $75 million and $43 million, respectively. Other inventories are generally stated at the lower of cost, determined on an average cost basis, or market.

UTILITY PLANT

The costs of additions, renewals and improvements to utility plant are charged to the appropriate plant accounts. These costs include labor, material, other direct costs, indirect charges, and an allowance for funds used during construction. The cost of utility plant retired or otherwise disposed of, plus removal costs and less salvage, is charged to accumulated depreciation. Depreciation is recorded on the straight-line remaining-life basis. The depreciation methods are consistent with those used by non-regulated entities.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

AFUDC represents the cost of funds used to finance the construction of utility plant and is added to its cost. Interest expense of $4 million, $6 million and $9 million in 1997, 1996 and 1995, respectively, was capitalized.

OTHER

Cash equivalents include short-term investments purchased with maturities of less than 90 days.

The preparation of financial statements in conformity with GAAP 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.

3. REGULATORY MATTERS

The Company is regulated by the CPUC. It is the responsibility of the CPUC to determine that utilities operate in the best interest of their customers while providing utilities with the opportunity to earn a reasonable return on investment.

PERFORMANCE BASED REGULATION

On July 16, 1997, the CPUC issued its final decision on the Company's application for performance based regulation (PBR), which was filed with the CPUC in 1995.

PBR replaces the general rate case and certain other regulatory proceedings through December 31, 2002. Under PBR, regulators allow future income potential to be tied to achieving or exceeding specific performance and productivity measures, rather than relying solely on expanding utility rate base in a market where the Company already has a highly developed infrastructure. Key elements of the PBR include a reduction in base rates, an indexing mechanism that limits future rate increases to the inflation rate less a productivity factor, a sharing mechanism with customers if earnings exceed the authorized rate of return on ratebase, and rate refunds to customers if service quality deteriorates. Specifically, the key elements of PBR include the following:

- The decision required a net rate reduction of $164 million for an initial base margin of $1.3 billion. The $164 million is comprised of a rate reduction of $191 million effective August 1, 1997, which is partially offset by an estimated $27 million rate increase reflecting inflation and customer growth, effective January 1, 1998.

- Earnings up to 25 basis points exceeding the authorized rate of return on ratebase are retained 100% by shareholders. Earnings that exceed the authorized rate of return on rate base by greater than 25 basis points are shared between customers and shareholders on a sliding scale that begins with 75% of earnings being given back to customers and declining to 0% as earned returns approach 300 basis points above authorized amounts. However, the decision rejects sharing of any amount by which actual earnings fall below the authorized rate of return. In 1998, the Company is authorized to earn a 9.49% return on rate base.

- Revenue or margin per customer is indexed based on inflation less an estimated productivity factor of 2.1% in the first year, increasing 0.1% per year up to 2.5% in the fifth year. This factor includes 1% to approximate the projected impact of a declining rate base.

- The CPUC decision allows for pricing flexibility for residential and small commercial customers, with any shortfalls being borne by shareholders and with any gains shared between shareholders and customers.

- The decision allows the Company to continue offering some types of products and services it currently offers (e.g. contract meter reading) but the issue of other new product and service offerings was addressed in the CPUC's Affiliate Transaction Decision.

The Company implemented the base margin reduction effective August 1, 1997, and all other PBR elements on January 1, 1998. The CPUC intends the PBR decision to be in effect for five years; however, the CPUC decision allows for the possibility that changes to the PBR mechanism could be adopted in a decision to be issued in the Company's 1998 Biennial Cost Allocation Proceeding (BCAP) application which is anticipated to become effective August 1, 1999.

Under PBR, annual cost of capital proceedings are replaced by an automatic adjustment mechanism if changes in certain indices exceed established tolerances. The mechanism is triggered if actual interest rates increase or decrease by more that 150 basis points and are forecasted to vary by at least 150 basis points for the next year. If this occurs, there would be an automatic adjustment of rates for the change in the cost of capital according to a pre-established formula which applies a percentage of the change to various capital components.

RESTRUCTURING OF GAS SUPPLY CONTRACTS

In 1993, the Company and its gas supply affiliates restructured long-term gas supply contracts with suppliers of California offshore and Canadian gas. In the past, the Company's cost of these supplies had been substantially in excess of its average delivered cost of gas for all gas supplies.

The restructured contracts substantially reduced the ongoing delivered costs of these gas supplies and provided lump sum payments totaling $391 million to the suppliers. The expiration date for the Canadian gas supply contract was shortened from 2012 to 2003.

COMPREHENSIVE SETTLEMENT OF REGULATORY ISSUES

On July 20, 1994, the CPUC approved a comprehensive settlement (Comprehensive Settlement) of a number of pending regulatory issues including rate recovery of a significant portion of the restructuring costs associated with long-term gas supply contracts discussed above. The Comprehensive Settlement permits the Company to recover in utility rates approximately 80% of the contract restructuring costs of $391 million and accelerated amortization of related pipeline assets of approximately $140 million, together with interest, over a period of approximately five years.

In addition to the gas supply issues, the Comprehensive Settlement addresses the following other regulatory issues:

- NONCORE CUSTOMER RATES. The Comprehensive Settlement changed the procedures for determining noncore rates to be charged by the Company to its customers for the five-year period commencing August 1, 1994. Rates charged to the customers are established based upon the Company's recorded throughput to these customers for 1991. The Company will bear the full risk of any declines in noncore deliveries from 1991 levels. Any revenue enhancement from deliveries in excess of 1991 levels will be limited by a crediting account mechanism that will require a credit to customers of 87.5% of revenues in excess of certain limits. These annual limits above which the credit is applicable increase from $11 million to $19 million over the five-year period from August 1, 1994 through July 31, 1999. The Company's ability to report as earnings the results from revenues in excess of its authorized return from noncore customers due to volume increases has been eliminated for the five years beginning August 1, 1994 as a result of the Comprehensive Settlement.

- REASONABLENESS REVIEWS. The Comprehensive Settlement includes settlement of all pending reasonableness reviews with respect to the Company's gas purchases from April 1989 through March 1992, as well as certain other future reasonableness review issues.

- GAS COST INCENTIVE MECHANISM. On April 1, 1994, the Company implemented a new process for evaluating the Company's gas purchases, substantially replacing the previous process of reasonableness reviews. Initially a three-year pilot program, the CPUC recently extended the Gas Cost Incentive Mechanism (GCIM) program through March 31, 1999.

  GCIM compares the Company's cost of gas with a benchmark level, which is the average price of 30-day firm spot supplies delivered to the Company's market area. The mechanism permits full recovery of all costs within a "tolerance band" above the benchmark price and refunds all savings within a "tolerance band" below the benchmark price. The costs of purchases or savings outside the "tolerance band" are shared equally between customers and shareholders.

  The CPUC approved the use of gas futures for managing risk associated with the GCIM. The Company enters into gas futures contracts in the open market on a limited basis to mitigate risk and better manage gas costs.

  Since the Company's purchase gas costs were below the specified GCIM benchmark for the annual period ended March 1996, the CPUC, in June 1997, approved a $3.2 million pre-tax award to shareholders under the procurement portion of the incentive mechanism. This $3.2 million award was recognized as income in the second quarter of 1997.

  In June 1997, the Company filed its annual GCIM application with the CPUC requesting an award of $10.8 million, pre-tax, for the annual period ended March 31, 1997. The CPUC is expected to issue a final decision on this matter by mid-1998, at which time the approved award will be recognized as income.

- ATTRITION ALLOWANCES. The Comprehensive Settlement authorized the Company an annual allowance for increases in operating and maintenance expenses. In 1996, attrition was calculated on the inflation rate in excess of 3% authorizing the Company to collect $12 million in rates. No attrition allowance was authorized for 1997 based on an agreement reached as part of the PBR application.

The Company recorded the impact of the Comprehensive Settlement in 1993. Upon giving effect to liabilities previously recognized by the Company, the costs of the Comprehensive Settlement, including the restructuring of gas supply contracts, did not result in any additional charge to the Parent's consolidated earnings.

BCAP

In the second quarter of 1997, the CPUC issued a decision on the Company's 1996 BCAP filing. The CPUC decision extends the recovery period of approximately $20 million in noncore costs, resulting in a noncore rate decrease and leaves in place the existing residential rate structure. The decision did not adopt the Company's proposal to increase flexibility in offering discounts to utility electric generating customers to retain load or prevent bypass. The Company implemented the new rates and core residential monthly gas pricing on June 1, 1997.

The BCAP substantially eliminates the effect on core income of variances in core market demand and gas costs subject to the limitations of the GCIM and the Comprehensive Settlement. The CPUC's PBR decision indicates that it will address issues such as throughput forecast, cost allocation, rate design and other matters which may arise from the Company's PBR experience during the 1998 BCAP.

TRANSACTIONS BETWEEN UTILITY AND AFFILIATED COMPANIES

On December 16, 1997, the CPUC adopted rules, effective January 1, 1998, establishing uniform standards of conduct governing the manner in which California investor-owned utilities conduct business with their energy-related affiliates (Energy Affiliates). The objective of the Affiliate Transaction rules is to ensure that utility affiliates do not gain an unfair advantage over other competitors in the marketplace and that utility customers do not subsidize affiliate activities. The rules establish standards relating to non-discrimination, disclosure, and information exchange and separation of activities.

Key elements of the Affiliate Transaction Decision are as follows:

- Allows unregulated affiliates to operate within the utility's service territory.

- Requires non-discriminatory pricing which mandates that all transactions between the utility and its Energy Affiliates be tariffed or competitively bid, excluding permitted corporate support services and certain joint purchases.

- Allows utilities to share logos with their parent company and their Energy Affiliates; however, in California, the relationship of the affiliated companies to the utility must be clearly communicated.

- Prohibits joint marketing activities and joint use of call centers by utilities and their Energy Affiliates.

- Permits corporate support services (such as corporate oversight, government support systems, and personnel) to be provided by the utility, its holding company or a separate affiliate created solely to provide such services.

- Prohibits utilities from sharing office space, computers and office equipment with Energy Affiliates, except in connection with providing corporate support services.

- Eliminates a parent company from the definition of an "affiliate" unless it is directly involved in marketing energy products or services.

Utility-to-utility transactions are also included under the definition of an affiliate transaction unless the rules are modified in a subsequent merger or other regulatory proceeding. On January 23, 1998, at the request of the Administrative Law Judge presiding over the Parent/Enova merger proceeding, the Parent and Enova jointly filed their comments regarding the impact of the Affiliate Transaction Decision on the original estimate of merger synergy savings. The filing indicated that the Affiliate Transaction rules, if applied to utility-to-utility transactions, would significantly reduce anticipated synergy savings previously discussed in Note 1.

As required by the decision, the Company has filed compliance plans with the CPUC addressing the Parent's implementation of the new rules. In addition, the Company has filed for exemptions on certain rules as well as petitions for rehearing which seek revision and clarification on certain aspects of the rules.

4. INCOME TAXES

A reconciliation of the difference between computed statutory federal income tax expense and actual income tax expense for operations is as follows:

	YEAR ENDED DECEMBER 31		
	1997	1996	1995
	(DOLLARS IN MILLIONS)		
Computed statutory federal income tax expense	$ 146	$ 122	$ 128
Increase (reductions) resulting from:			
Excess book over tax depreciation	23	23	20
State income taxes--net of federal income tax benefit	26	19	21
Capitalized expenses not deferred	(3)	(11)	(10)
Amortization of deferred investment tax credits	(3)	(3)	(3)
Resolution of proposed tax deficiency	(6)	(4)	(3)
Other--net	(5)	2	(2)
Total income tax expense	$ 178	$ 148	$ 151

The components of income tax expense are as follows:

	YEAR ENDED DECEMBER 31		
	1997	1996	1995
	(DOLLARS IN MILLIONS)		
Federal:			
Current	$ 138	$ 100	$ 119
Deferred	3	18	0
	141	118	119
State:			
Current	38	30	37
Deferred	(1)	0	(5)
	37	30	32
Total:			
Current	176	130	156
Deferred	2	18	(5)
	$ 178	$ 148	$ 151

The principal components of net deferred tax liabilities are as follows:

	DECEMBER 31					
	1997			1996		
	ASSETS	LIABILITIES	TOTAL	ASSETS	LIABILITIES	TOTAL
	(DOLLARS IN MILLIONS)					
Depreciation		$ (455)	$ (455)		$ (455)	$ (455)
Comprehensive Settlement	$ 114		114	$ 134	(47)	87
Regulatory accounts receivable		(161)	(161)		(132)	(132)
Deferred investment tax credits	27		27	28		28
Customer advances for construction	14		14	20		20
Regulatory asset		(11)	(11)		(24)	(24)
Other regulatory	158	(48)	110	143	(50)	93
Total deferred income tax assets (liabilities)	$ 313	$ (675)	$ (362)	$ 325	$ (708)	$ (383)

The Parent files a consolidated federal income tax return and combined California franchise tax reports which include the Company and the Parent's other subsidiaries. The Company pays the amount of taxes applicable to itself had it filed a separate return.

The Company generally provides for income taxes on the basis of amounts expected to be paid currently, except for the provision for deferred taxes on regulatory accounts, customer advances for construction and accelerated depreciation of property placed in service after 1980. In addition, the Company recognizes certain other deferred tax liabilities (primarily accelerated depreciation of property placed in service prior to 1981 and deferred investment tax credits) which are expected to be recovered through future rates. At December 31, 1997 and 1996, $66 million and $93 million, respectively, of deferred income taxes have been offset by an equivalent amount in regulatory assets.

5. COMMITMENTS AND CONTINGENT LIABILITIES

ENVIRONMENTAL OBLIGATIONS

The Company has identified and reported to California environmental authorities 42 former manufactured gas plant sites for which it (together with other utilities as to 21 of these sites) may have remedial obligations under environmental laws. As of December 31, 1997, ten of these sites have been remediated, of which seven have received certification from the California Environmental Protection Agency. Two sites are in the process of being remediated. Preliminary investigations, at a minimum, have been completed on 39 of the gas plant sites, including those sites at which the remediations described above have been completed. In addition, the Company has been named as a potentially responsible party for two landfill sites and two industrial waste disposal sites.

In 1994, the CPUC approved a collaborative settlement which provides for rate recovery of 90% of environmental investigation and remediation costs without reasonableness reviews. In addition, the Company has the opportunity to retain a percentage of any insurance recoveries to offset the 10% of costs not recovered in rates.

At December 31, 1997, the Company's estimated remaining investigation and remediation liability was $72 million, of which 90% is authorized to be received through the mechanism discussed above. The Company believes that any costs not ultimately recovered through rates, insurance or other means, upon giving effect to previously established liabilities, will not have a material adverse effect on the Company's consolidated results of operations or financial position.

Estimated liabilities for environmental remediation are recorded when amounts are probable and estimable. Amounts authorized to be recovered in rates under the mechanism described above are recorded as a regulatory asset. Possible recoveries of environmental remediation liabilities from third parties are not deducted from the liability.

LITIGATION

The Company is a defendant in various lawsuits arising in the normal course of business. The Company believes that the resolution of these pending claims and legal proceedings will not have a material adverse effect on the Company's consolidated results of operations or financial position.

OBLIGATIONS UNDER FIRM COMMITMENTS

The Company has commitments for firm pipeline capacity under contracts with pipeline companies that expire at various dates through the year 2006. These agreements provide for payments of an annual reservation charge. The Company recovers such fixed charges in rates. Estimated minimum commitments as of December 31, 1997 are as follows: 1998--$179 million, 1999--$182 million, 2000--$184 million, 2001--$186 million, 2002--$186 million, after 2002--$635 million.

OTHER COMMITMENTS AND CONTINGENCIES

At December 31, 1997, commitments for capital expenditures were approximately $16 million.

6. LEASES

The Company has leases on real and personal property expiring at various dates from 1998 to 2011. The rentals payable under these leases are determined on both fixed and percentage bases and most leases contain options to extend which are exercisable by the Company.

Rental expense under operating leases was $44 million, $45 million and $45 million in 1997, 1996 and 1995, respectively. The following is a schedule of future minimum operating lease commitments as of December 31, 1997:

	FUTURE MINIMUM LEASE PAYMENTS (DOLLARS IN MILLIONS)
Year Ending December 31:	
1998	$ 19
1999	19
2000	18
2001	16
2002	18
Later years	159
Total	$ 249

7. COMPENSATING BALANCES AND SHORT-TERM BORROWING ARRANGEMENTS

The Company has a $650 million multi-year credit agreement requiring annual fees of .07%. The interest rate on this line varies and is derived from formulas based on market rates and the Company's credit ratings. The multi-year credit agreement expires in February 2001. The Company's line of credit provides backing for its commercial paper program. At December 31, 1997, the bank line of credit was unused.

At December 31, 1997 and 1996, the Company had $351 million and $358 million, respectively, of commercial paper obligations outstanding. Approximately $94 million of the outstanding commercial paper relates to the restructuring costs associated with certain long-term gas supply contracts under the Comprehensive Settlement (See Note 3). The weighted average annual interest rate of commercial paper obligations outstanding was 5.78% and 5.36% at December 31, 1997 and 1996, respectively.

At December 31, 1996, the Company classified $96 million of the commercial paper as long-term debt, since it was the Company's intent to continue to refinance that portion of the debt on a long-term basis. No commercial paper was reclassified as long-term debt at December 31, 1997.

8. LONG-TERM DEBT

	DECEMBER 31 1997	DECEMBER 31 1996
	(DOLLARS IN MILLIONS)	
FIRST MORTGAGE BONDS:		
6 1/2% December 15, 1997		$ 125
5 1/4% March 1, 1998	$ 100	100
6 7/8% August 15, 2002	100	100
5 3/4% November 15, 2003	100	100
8 3/4% October 1, 2021	150	150
7 3/8% March 1, 2023	100	100
7 1/2% June 15, 2023	125	125
6 7/8% November 1, 2025	175	175
OTHER LONG-TERM DEBT:		
5.98% Notes, August 28, 1997		22
6.21% Notes, November 1, 1999	75	75
6 3/8% Notes, October 29, 2001	120	
8 3/4% Notes, July 6, 2000	30	30
SFr. 100,000,000 5 1/8% Bonds, February 6, 1998 (foreign currency exposure hedged through currency swap at an interest rate of 9.725%)	47	47
5.33% Commercial Paper, February 8, 2001		96
Other, 6 3/8%, May 14, 2006	8	8
Total outstanding	1,130	1,253
Less:		
Payments due within one year	147	147
Unamortized debt discount less premium	15	16
	162	163
Long-Term Debt	$ 968	$ 1,090

The annual principal payment requirements of long-term debt for the years 1998 through 2002 are $147 million, $75 million, $30 million, $120 million and $100 million, respectively. Substantially all of utility plant serves as collateral for the First Mortgage Bonds.

CURRENCY RATE SWAPS

In February 1986, the Company issued SFr. 100 million of 5 1/8% bonds maturing on February 6, 1998. The Company hedged the currency exposure by entering into a swap transaction with a major international bank. As a result, the bond issue, interest payments, and other ongoing costs were swapped for fixed annual payments. The terms of the swap result in a U.S. dollar liability of $47 million at an interest rate of 9.725%.

9. FINANCIAL INSTRUMENTS

The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. The amounts disclosed represent management's best estimates of fair value.

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, accounts payable and short-term debt approximated fair value as of December 31, 1997 and 1996 because of the relatively short maturity of those instruments. The carrying amount of the currency swaps approximates fair value.

The fair value of the Company's long-term debt, 6% preferred, and 7 3/4% preferred stock is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for debt of similar remaining maturities. The fair value of these financial instruments is different from the carrying amount.

The following financial instruments have a fair value which is different from the carrying amount as of December 31.

	1997		1996	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(DOLLARS IN MILLIONS)			
Long-Term Debt	$ 1,115	$ 1,159	$ 1,237	$ 1,248
Preferred Stocks	$ 97	$ 95	$ 97	$ 93

As a result of the GCIM (See Note 3), the Company enters into a certain amount of gas futures contracts in the open market with the intent of reducing gas costs within the GCIM tolerance band. The Company's policy is to use gas futures contracts to mitigate risk and better manage gas costs. The CPUC has approved the use of gas futures for managing risk associated with the GCIM. For the year ended December 31, 1997, gains or losses from gas futures contracts are not material to the Company's financial statements.

10. CAPITAL STOCK

The amount of capital stock outstanding at December 31, is as follows:

	DECEMBER 31, 1997		DECEMBER 31, 1996	
	NUMBER OF SHARES	MILLIONS OF DOLLARS	NUMBER OF SHARES	MILLIONS OF DOLLARS
PREFERRED STOCK:				
cumulative, voting(a)(b):				
6%, $25 par value	79,011	$ 3	79,011	$ 3
6%, Series A, $25 par value	783,032	19	783,032	19
Series Preferred, no par value 7 3/4%, $25 Stated Value(c)	3,000,000	75	3,000,000	75
Total		$ 97		$ 97
PREFERENCE STOCK--cumulative, voting, no par value(a)(b)				
COMMON STOCK--no par value(a)(b)	91,300,000	$ 835	91,300,000	$ 835

- ------------------------

(a) The Company's Articles of Incorporation authorize the following stocks: 100 million shares of Common Stock without par value; 160,000 shares of 6% Preferred Stock--$25.00 par value; 840,000 shares of 6% Preferred Stock--$25.00 par value, Series A; 5 million shares of Series Preferred Stock without par value and 5 million shares of Preference Stock without par value.

(b) In the event of any liquidation, dissolution or winding up of the Company, the holders of shares of each series of Preferred Stock and of each series of Series Preferred Stock would be entitled to receive the stated value or the liquidation preference for their shares, plus accrued dividends before any amount shall be paid to the holders of Preference Stock or Common Stock. If the amounts payable with respect to the shares of each series of Preferred Stock or Series Preferred Stock are not paid in full, the holders of such shares will share ratably in any such distribution. After payment in full to the holders of each series of Preferred Stock, Series Preferred Stock and Preference Stock of the liquidating distributions to which they are entitled, the remaining assets and funds of the Company would be divided PRO RATA among the holders of Preferred Stock and the holders of Common Stock.

(c) On February 2, 1998, the Company redeemed all outstanding shares of 7 3/4% Series Preferred Stock at a total price of $25.09. This total price per share consisted of a redemption price of $25 and $.09 of unpaid dividends accruing to the date of redemption. The total cost to the Company was approximately $75.3 million.

11. TRANSACTIONS WITH AFFILIATES

Pacific Interstate Transmission Company, Pacific Interstate Offshore Company and Pacific Offshore Pipeline Company, subsidiaries of the Parent and gas supply affiliates of the Company, sell and transport gas to the Company under tariffs approved by the Federal Energy Regulatory Commission. During 1997, 1996, and 1995, billings for such gas purchases totaled $252 million, $186 million and $141 million, respectively. The Company has long-term gas purchase and transportation agreements with the affiliates extending through the year 2003 requiring certain minimum payments which allow the affiliates to recover the construction cost of their facilities. The Company is obligated to make minimum annual payments to cover the affiliates' operation and maintenance expenses, demand charges paid to their suppliers, current taxes other than income taxes, and debt service costs, including interest expense and scheduled retirement of debt. These long-term agreements were restructured in conjunction with the Comprehensive Settlement previously discussed (see Note 3).

12. PENSION, POSTRETIREMENT AND OTHER EMPLOYEE BENEFIT PLANS

PENSION PLAN

The Company has a noncontributory defined benefit pension plan covering substantially all of its employees. Benefits are based on an employee's years of service and compensation during his or her last years of employment. The Company's policy is to fund the plan annually at a level which is fully deductible for federal income tax purposes and as necessary on an actuarial basis to provide assets sufficient to meet the benefits to be paid to plan members.

In conformity with generally accepted accounting principles for a rate regulated enterprise, the Company has recorded regulatory adjustments to reflect, in net income, pension costs calculated under the actuarial method allowed for ratemaking. The cumulative difference between the net periodic pension cost calculated for financial reporting and ratemaking purposes has been included as a deferred charge or credit in the Consolidated Balance Sheet.

Pension expense was as follows:

	YEAR ENDED DECEMBER 31		
	1997	1996	1995
	(DOLLARS IN MILLIONS)		
Service cost on benefits earned during the period	$ 32	$ 34	$ 26
Interest cost on projected benefit obligation	94	93	84
Actual return on plan assets	(268)	(204)	(315)
Net amortization and deferral	142	100	211
Net periodic pension cost		23	6
Special early retirement program	13		18
Regulatory adjustment		3	4
Total pension expense	$ 13	$ 26	$ 28

A reconciliation of the plan's funded status to the pension liability recognized in the Consolidated Balance Sheet is as follows:

	DECEMBER 31	
	19967	1996
	(DOLLARS IN MILLIONS)	
Actuarial present value of pension benefit obligations:		
Accumulated benefit obligation, including $1,057 and $1,048 in vested benefits at December 31, 1997 and 1996, respectively	$ 1,105	$ 1,082
Effect of future salary increases	261	208
Projected benefit obligation	1,366	1,290
Less: plan assets at fair value, primarily publicly traded common stocks and pooled equity funds	(1,834)	(1,653)
Unrecognized net gain	520	404
Unrecognized prior service cost	(36)	(38)
Unrecognized transition obligation	(4)	(4)
Accrued pension liability included in the Consolidated Balance Sheet	$ 12	$ (1)
Deferred pension charge included in the Consolidated Balance Sheet	$	$ (3)
The plans' major actuarial assumptions include:		
Weighted average discount rate	7.00%	7.50%
Rate of increase in future compensation levels	5.00%	5.00%
Expected long-term rate of return on plan assets	8.00%	8.00%

POSTRETIREMENT BENEFIT PLANS

The Company's postretirement benefit plan currently provides medical and life insurance benefits to qualified retirees. In the past, employee cost-sharing provisions have been implemented to control the increasing costs of these benefits. Other changes could occur in the future. The Company's policy is to fund these benefits at a level which is fully deductible for federal income tax purposes, not to exceed amounts recoverable in rates for regulated companies, and as necessary on an actuarial basis to provide assets sufficient to be paid to plan participants.

Separate trusts for each of the plans have been established exclusively for the benefit payments of each plan. Some of the plans' funds are commingled with the pension funds by the trustee for investment purposes but are accounted for separately per plan.

The net periodic postretirement benefit expense was as follows:

	YEAR ENDED DECEMBER 31		
	1997	1996	1995
	(DOLLARS IN MILLIONS)		
Service cost on benefits earned during the period	$ 13	$ 15	$ 12
Interest cost on projected benefit obligation	31	30	29
Actual return on plan assets	(56)	(30)	(36)
Net amortization and deferral	44	24	35
Net periodic postretirement benefit cost	32	39	40
Special early retirement program	2		
Regulatory adjustment		(1)	(1)
Total postretirement benefit expense	$ 34	$ 38	$ 39

A reconciliation of the plan's funded status to the postretirement liability recognized in the Consolidated Balance Sheet is as follows:

	DECEMBER 31	
	1997	1996
	(DOLLARS IN MILLIONS)	
Accumulated post-retirement benefit obligation:		
Retirees	$ 202	$ 192
Fully eligible active plan participants	234	156
Other active plan participants	27	19
	463	367
Less: plan assets at fair value, primarily publicly traded common stocks and pooled equity funds	(343)	(264)
Unrecognized net transition obligation	(128)	(132)
Unrecognized net pension service cost		
Unrecognized net gain	8	29
Net postretirement benefit liability included in the Consolidated Balance Sheet	$	$
Deferred postretirement benefit charge included in the Consolidated Balance Sheet	$	$ (1)
The plan's major actuarial assumptions include:		
Health care cost trend rate	7.00%	7.00%
Weighted average discount rate	7.00%	7.50%
Rate of increase in future compensation levels	5.00%	5.00%
Expected long-term rate of return on plan assets	8.00%	8.00%

The assumed and ultimate health care cost trend rate is 6.5% for 1998 and thereafter. The effect of a one-percentage-point increase in the assumed health care cost trend rate for each future year is $9.2 million on the aggregate of the service and interest cost components of net periodic postretirement cost for 1997 and $68.8 million on the accumulated postretirement benefit obligation at December 31, 1997. The estimated income tax rate used in the return on plan assets is zero since the assets are invested in tax exempt funds.

POSTEMPLOYMENT BENEFITS

The Company accrues its obligation to provide benefits to former or inactive employees after employment but before retirement. There was no impact on earnings since these costs are currently recovered in rates as paid, and as such, have been reflected as a regulatory asset. At December 31, 1997 and 1996 the liability was $39 million and $40 million, respectively, and represents primarily workers compensation and disability benefits.

RETIREMENT SAVINGS PLAN

Upon completion of one year of service, all employees of the Company and certain subsidiaries are eligible to participate in the Company's retirement savings plan administered by bank trustees. Employees may contribute from 1% to 14% of their regular earnings. The Company generally contributes an amount of cash or a number of shares of the Company's common stock of equivalent fair market value which, when added to prior forfeitures, will equal 50% of the first 6% of eligible base salary contributed by employees. The employees' contributions, at the direction of the employees, are primarily invested in the Company's common stock, mutual funds or guaranteed investment contracts. In 1995, 1996 and 1997 the Company's contributions were partially funded by the Pacific Enterprises Employee Stock Ownership Plan and Trust. The Company's compensation expense was $7 million in 1997, 1996 and 1995.

STATEMENT OF MANAGEMENT RESPONSIBILITY FOR CONSOLIDATED FINANCIAL SERVICES

The consolidated financial statements have been prepared by management. The integrity and objectivity of these financial statements and the other financial information in the Annual Report, including the estimates and judgments on which they are based, are the responsibility of management. The financial statements have been audited by Deloitte & Touche LLP, independent certified public accountants, appointed by the Board of Directors. Their report is shown on page 47. Management has made available to Deloitte & Touche LLP all of the Company's financial records and related data, as well as the minutes of shareholders' and directors' meetings.

Management maintains a system of internal accounting control which it believes is adequate to provide reasonable, but not absolute, assurance that assets are properly safeguarded and accounted for, that transactions are executed in accordance with management's authorization and are properly recorded and reported, and for the prevention and detection of fraudulent financial reporting. Management monitors the system of internal control for compliance through its own review and a strong internal auditing program which also independently assesses the effectiveness of the internal controls. In establishing and maintaining internal controls, the Company must exercise judgment in determining whether the benefits to be derived justify the costs of such controls.

Management acknowledges its responsibility to provide financial information (both audited and unaudited) that is representative of the Company's operations, reliable on a consistent basis, and relevant for a meaningful financial assessment of the Company. Management believes that the control process enables them to meet this responsibility.

Management also recognizes its responsibility for fostering a strong ethical climate so that the Company's affairs are conducted according to the highest standards of personal and corporate conduct. This responsibility is characterized and reflected in the Company's code of corporate conduct, which is publicized throughout the Company. The Company maintains a systematic program to assess compliance with this policy.

The Board of Directors has an Audit Committee composed solely of directors who are not officers or employees. The Committee recommends for approval by the full Board the appointment of the independent auditors. The Committee meets regularly with management, with the Company's internal auditors, and with the independent auditors. The independent auditors and the internal auditors periodically meet alone with the Audit Committee and have free access to the Audit Committee at any time.

Warren I. Mitchell,
PRESIDENT

Neal E. Schmale,
EXECUTIVE VICE PRESIDENT AND CHIEF
FINANCIAL OFFICER

January 27, 1998

INDEPENDENT AUDITORS' REPORT

Southern California Gas Company:

We have audited the consolidated financial statements of Southern California Gas Company and subsidiaries (pages 27 to 45) as of December 31, 1997 and 1996, and 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Southern California Gas Company 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.

DELOITTE & TOUCHE LLP

Los Angeles, California
January 27, 1998

QUARTERLY FINANCIAL DATA (UNAUDITED)

	1997			
	THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	(DOLLARS IN MILLIONS)			
Operating revenues	$ 738	$ 575	$ 607	$ 721
Net operating revenue	$ 82	$ 91	$ 72	$ 73
Net income	$ 60	$ 72	$ 55	$ 51
Net income applicable to common stock	$ 58	$ 70	$ 54	$ 49

	1996			
	THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	(DOLLARS IN MILLIONS)			
Operating revenues	$ 620	$ 497	$ 575	$ 730
Net operating revenue	$ 79	$ 54	$ 73	$ 80
Net income	$ 57	$ 32	$ 53	$ 59
Net income applicable to common stock	$ 54	$ 30	$ 51	$ 58

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information required by this Item with respect to the Company's directors is set forth under the caption "Election of Directors" in the Company's Information Statement for its Annual Meeting of Shareholders scheduled to be held on May 5, 1998. Such information is incorporated herein by reference.

Information required by this Item with respect to the Company's executive officers is set forth in Item 1 of this Annual Report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this Item is set forth under the caption "Election of Directors" and "Executive Compensation" in the Company's Information Statement for its Annual Meeting of Shareholders scheduled to be held on May 5, 1998. Such information is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by this Item is set forth under the caption "Election of Directors" in the Company's Information Statement for its Annual Meeting of Shareholders scheduled to be held on May 5, 1998. Such information is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) Documents filed as part of this report:

1. CONSOLIDATED FINANCIAL STATEMENTS (SET FORTH IN ITEM 8 OF THIS ANNUAL REPORT ON FORM 10-K):

   1.01 Independent Auditors' Report.

   1.02 Statement of Consolidated Income for the years ended December 31, 1997, 1996, and 1995.

   1.03 Consolidated Balance Sheet at December 31, 1997 and 1996.

   1.04 Statement of Consolidated Cash Flows for the years ended December 31, 1997, 1996 and 1995.

   1.05 Statement of Consolidated Shareholders' Equity for the years ended December 31, 1997, 1996, 1995 and 1994.

   1.06 Notes to Consolidated Financial Statements.

2. FINANCIAL STATEMENT SCHEDULES: Schedules for which provision is made in Regulation S-X are not required under the instructions contained therein, are inapplicable, or the information is included in the Notes to the Consolidated Financial Statements.

3. ARTICLES OF INCORPORATION AND BY-LAWS:

   3.01 Restated Articles of Incorporation of Southern California Gas Company (Note 29; Exhibit 3.01).

   3.02 Bylaws of Southern California Gas Company. (Note 28; Exhibit 3.02)

4. INSTRUMENTS DEFINING THE RIGHTS OF SECURITY HOLDERS:

   (Note: As permitted by Item 601(b)(4)(iii) of Regulation S-K, certain instruments defining the rights of holders of long-term debt for which the total amount of securities authorized thereunder does not exceed ten percent of the total assets of Southern California Gas Company and its subsidiaries on a consolidated basis are not filed as exhibits to this Annual Report. The Company agrees to furnish a copy of each such instrument to the Commission upon request.)

   4.01 Specimen Preferred Stock Certificates of Southern California Gas Company (Note 13; Exhibit 4.01).

   4.02 First Mortgage Indenture of Southern California Gas Company to American Trust Company dated as of October 1, 1940 (Note 1; Exhibit B-4).

   4.03 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of July 1, 1947 (Note 2; Exhibit B-5).

   4.04 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of August 1, 1955 (Note 3; Exhibit 4.07).

   4.05 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of June 1, 1956 (Note 4; Exhibit 2.08).

   4.06 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of August 1, 1972 (Note 7; Exhibit 2.19).

   4.07 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of May 1, 1976 (Note 6; Exhibit 2.20).

4.08 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of September 15, 1981 (Note 12; Exhibit 4.25).

4.09 Supplemental Indenture of Southern California Gas Company to Manufacturers Hanover Trust Company of California, successor to Wells Fargo Bank, National Association, and Crocker National Bank as Successor Trustee dated as of May 18, 1984 (Note 16; Exhibit 4.29).

4.10 Supplemental Indenture of Southern California Gas Company to Bankers Trust Company of California, N.A., successor to Wells Fargo Bank, National Association dated as of January 15, 1988 (Note 18; Exhibit 4.11).

4.11 Supplemental Indenture of Southern California Gas Company to First Trust of California, National Association, successor to Bankers Trust Company of California, N.A. dated as of August 15, 1992 (Note 24; Exhibit 4.37).

4.12 Specimen 7 3/4% Series Preferred Stock Certificate (Note 25; Exhibit 4.15).

10. MATERIAL CONTRACTS

10.01 Restatement and Amendment of Pacific Enterprises 1979 Stock Option Plan (Note 10; Exhibit 1.1).

10.02 Pacific Enterprises Supplemental Medical Reimbursement Plan for Senior Officers (Note 11; Exhibit 10.24).

10.03 Pacific Enterprises Financial Services Program for Senior Officers (Note 11; Exhibit 10.25).

10.04 Southern California Gas Company Retirement Savings Plan, as amended and restated as of August 30, 1988 (Note 15; Exhibit 28.02).

10.05 Southern California Gas Company Statement of Life Insurance, Disability Benefit and Pension Plans, as amended and restated as of January 1, 1985 (Note 16; Exhibit 10.27).

10.06 Southern California Gas Company Pension Restoration Plan For Certain Management Employees (Note 11; Exhibit 10.29).

10.07 Pacific Enterprises Executive Incentive Plan (Note 18; Exhibit 10.13)

10.08 Pacific Enterprises Deferred Compensation Plan for Key Management Employees (Note 15; Exhibit 10.41).

10.09 Pacific Enterprises Stock Incentive Plan (Note 19; Exhibit 4.01).

10.10 Amended and Restated Pacific Enterprises Employee Stock Option Plan (Note 29; Exhibit 10.10).

10.11 Master Affiliate Service Agreement dated as of September 1, 1996 between Southern California Gas Company and Pacific Enterprises Energy Services, as amended (Note 29; Exhitit 10.11).

21. SUBSIDIARIES OF THE REGISTRANT

21.01 List of subsidiaries of Southern California Gas Company.

23. CONSENTS OF EXPERTS AND COUNSEL

23.01 Independent Auditors' Consent.

24. POWER OF ATTORNEY

24.01 Power of Attorney of Certain Officers and Directors of Southern California Gas Company (contained on the signature pages of this Annual Report on Form 10-K).

27. FINANCIAL DATA SCHEDULE

27.01 Financial Data Schedule.

(b) Reports on Form 8-K:

No reports on Form 8-K were filed during the last quarter of 1997.

- ------------------------

NOTE: Exhibits referenced to the following notes were filed with the documents cited below under the exhibit or annex number following such reference. Such exhibits are incorporated herein by reference.

NOTE REFERENCE	DOCUMENT
1	Registration Statement No. 2-4504 filed by Southern California Gas Company on September 16, 1940.
2	Registration Statement No. 2-7072 filed by Southern California Gas Company on March 15, 1947.
3	Registration Statement No. 2-11997 filed by Pacific Lighting Corporation on October 26, 1955.
4	Registration Statement No. 2-12456 filed by Southern California Gas Company on April 23, 1956.
5	Registration Statement No. 2-45361 filed by Southern California Gas Company on August 16, 1972.
6	Registration Statement No. 2-56034 filed by Southern California Gas Company on April 14, 1976.
7	Registration Statement No. 2-59832 filed by Southern California Gas Company on September 6, 1977.
8	Registration Statement No. 2-42239 filed by Pacific Lighting Gas Supply Company (under its former name of Pacific Lighting Service Company) on October 29, 1971.
9	Registration Statement No. 2-43834 filed by Pacific Lighting Corporation on April 17, 1972.
10	Registration Statement No. 2-66833 filed by Pacific Lighting Corporation on March 5, 1980.
11	Annual Report on Form 10-K for the year ended December 31, 1980, filed by Pacific Lighting Corporation.
12	Annual Report on Form 10-K for the year ended December 31, 1981, filed by Pacific Lighting Corporation.
13	Annual Report on Form 10-K for the year ended December 31, 1980 filed by Southern California Gas Company.
14	Quarterly Report on Form 10-Q for the quarter ended September 30, 1983, filed by Southern California Gas Company.
15	Registration Statement No. 33-6357 filed by Pacific Enterprises on December 30, 1988.
16	Annual Report on Form 10-K for the year ended December 31, 1984, filed by Southern California Gas Company.
17	Current Report on Form 8-K for the month of March 1986, filed by Southern California Gas Company.
18	Annual Report on Form 10-K for the year ended December 31, 1987 filed by Pacific Lighting Corporation.
19	Registration Statement No. 33-21908 filed by Pacific Enterprises on May 17, 1988.
20	Annual Report on Form 10-K for the year ended December 31, 1988, filed by Southern California Gas Company.
21	Annual Report on Form 10-K for the year ended December 31, 1989, filed by Southern California Gas Company.
22	Annual Report on Form 10-K for the year ended December 31, 1990, filed by Southern California Gas Company.
23	Annual Report on Form 10-K for the year ended December 31, 1991, filed by Southern California Gas Company.

NOTE REFERENCE	DOCUMENT
24	Registration Statement No. 33-50826 filed by Southern California Gas Company on August 13, 1992.
25	Annual Report on Form 10-K for the year ended December 31, 1992, filed by Southern California Gas Company.
26	Annual Report on Form 10-K for the year ended December 31, 1993, filed by Southern California Gas Company.
27	Registration Statement No. 33-54055 filed by Pacific Enterprises on June 9, 1994.
28	Annual Report on Form 10-K for the year ended December 31, 1995, filed by Southern California Gas Company.
29	Annual Report on Form 10-K for the year ended December 31, 1996, filed by Southern California Gas Company.

SIGNATURES

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

SOUTHERN CALIFORNIA GAS COMPANY

By: /s/ WARREN I. MITCHELL

Name: Warren I. Mitchell
Title: PRESIDENT

Dated: March 20, 1998

Each person whose signature appears below hereby authorizes Warren I. Mitchell, Neal E. Schmale, Ralph Todaro, and each of them, severally, as attorney-in-fact, to sign on his or her behalf, individually and in each capacity stated below, and file all amendments to this Annual Report.

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

NAME	TITLE	DATE
/s/ WARREN I. MITCHELL (Warren I. Mitchell)	President (Principal Executive Officer)	March 20, 1998
/s/ NEAL E. SCHMALE (Neal E. Schmale)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 20, 1998
/s/ RALPH TODARO (Ralph Todaro)	Vice President and Controller (Principal Accounting Officer)	March 20, 1998
/s/ HYLA H. BERTEA (Hyla H. Bertea)	Director	March 20, 1998
/s/ HERBER L. CARTER (Herbert L. Carter)	Director	March 20, 1998
/s/ WILFORD D. GODBOLD, JR. (Wilford D. Godbold, Jr.)	Director	March 20, 1998

NAME	TITLE	DATE
/s/ IGNACIO E. LOZANO, JR. (Ignacio E. Lozano, Jr.)	Director	March 20, 1998
/s/ RICHARD J. STEGEMEIER (Richard J. Stegemeier)	Director	March 20, 1998
/s/ DIANA L. WALKER (Diana L. Walker)	Director	March 20, 1998

Exhibit 21.01

Subsidiaries of Southern California Gas Company

EcoTrans OEM Corporation
Southern California Gas Tower

EXHIBIT 23.01

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Nos. 333-45537, 33-51322, 33-53258, 33-59404 and 33-52663 of Southern California Gas Company on Forms S-3 of our report dated January 27, 1998, appearing in this Annual Report on Form 10-K of Southern California Gas Company for the year ended December 31, 1997.

DELOITTE & TOUCHE LLP

Los Angeles, California
March 23, 1998

UT

THIS SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE
CONDENSED STATEMENT OF CONOLIDATED INCOME, BALANCE SHEET AND CASH FLOWS AND IS
QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.

1,000,000

12-MOS
DEC-31-1997
DEC-31-1997
PER-BOOK
3,074
0
917
214
0
4,205
835
0
535
1,370
0
97
968
351
0
0
147
0
0
0
1,272
4,205
2,641
174
2,149
2,323
318
7
325
87
238
7
231
0
0
396
0
0