SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

(Mark One)

[X] Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2000

OR

[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from ------- to -------

SEMPRA ENERGY

(Exact name of registrant as specified in its charter)

CALIFORNIA	1-14201	33-0732627
(State of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

101 ASH STREET, SAN DIEGO, CALIFORNIA	92101
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (619)696-2000

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, Without Par Value	New York and Pacific

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months 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. [ ]

Exhibit Index on page 34. Glossary on page 41.

Aggregate market value of the voting stock held by non-affiliates of the registrant as of February 28, 2001 was $4.5 billion.

Registrant's common stock outstanding as of February 28, 2001 was 204,977,870 shares.

DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the 2000 Annual Report to Shareholders are incorporated by reference into Parts I, II, and IV.

Portions of the Proxy Statement prepared for the May 2001 annual meeting of shareholders are incorporated by reference into Part III.

TABLE OF CONTENTS

This Annual Report contains statements that are not historical fact and constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, including statements regarding San Diego Gas & Electric Company's ability to finance undercollected costs on reasonable terms and retain its financial strength, estimates of future accumulated undercollected costs, and plans to obtain future financing. The words "estimates," "believes," "expects," "anticipates," "plans," "intends," "may," "would" and "should" or similar expressions, or discussions of strategy or of plans are intended to identify forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future results may differ materially from those expressed in these forward-looking statements.

Forward-looking statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others, local, regional, national and international economic, competitive, political, legislative and regulatory conditions; actions by the California Public Utilities Commission, the California Legislature, the California Department of Water Resources and the Federal Energy Regulatory Commission; the financial condition of other investor-owned utilities; inflation rates and interest rates; energy markets, including the timing and extent of changes in commodity prices; weather conditions; business, regulatory and legal decisions; the pace of deregulation of retail natural gas and electricity delivery; the timing and success of business-development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the Company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the Company's business described in this Annual Report and other reports filed by the Company from time to time with the Securities and Exchange Commission.

PART I

ITEM 1. BUSINESS

Description of Business
A description of Sempra Energy and its subsidiaries (the Company) is given in "Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2000 Annual Report to Shareholders, which is incorporated by reference.

GOVERNMENT REGULATION

The most significant government regulation affecting Sempra Energy is that affecting its utility subsidiaries, which is discussed below. Other subsidiaries are also subject to governmental regulation.

Local Regulation
Southern California Gas Company (SoCalGas) has gas franchises with the 238 legal jurisdictions in its service territory. These franchises allow SoCalGas to locate facilities for the transmission and distribution of natural gas in the streets and other public places. Some franchises have fixed terms, such as that for the city of Los Angeles, which expires in 2012. Most of the franchises do not have fixed terms and continue indefinitely. The range of expiration dates for the franchises with definite terms is 2003 to 2048.

San Diego Gas and Electric (SDG&E) has electric franchises with the three counties and the 25 cities and gas franchises with two counties and the 25 cities in its service territory. These franchises allow SDG&E to locate facilities for the transmission and distribution of electricity and/or natural gas in the streets and other public places. The franchises do not have fixed terms, except for the electric and natural gas franchises with the cities of Chula Vista (2003), Encinitas (2012), San Diego (2021) and Coronado (2028); and the natural gas franchises with the city of Escondido (2036) and the county of San Diego (2030).

California Utility Regulation
The State of California Legislature, from time to time, passes laws that regulate SDG&E's and SoCalGas' operations. For example, in 1996 the legislature passed an electric industry deregulation bill, then in 2000 and 2001 passed additional bills aimed at addressing problems in the deregulated electric industry. In addition, the legislature enacted a law in 1999 addressing natural gas industry restructuring.

The California Public Utilities Commission (CPUC) regulates SDG&E's and SoCalGas' rates and conditions of service, sales of securities, rate of return, rates of depreciation, uniform systems of accounts, examination of records, and long-term resource procurement. The CPUC also conducts various reviews of utility performance and conducts investigations into various matters, such as deregulation, competition and the environment, to determine its future policies.

The California Energy Commission (CEC) has discretion over electric-demand forecasts for the state and for specific service territories. Based upon these forecasts, the CEC determines the need for additional energy sources and for conservation programs. The CEC sponsors alternative-energy research and development projects, promotes energy conservation programs and maintains a state-wide plan of action in case of energy shortages. In addition, the CEC certifies power-plant sites and related facilities within California.

United States Utility Regulation
The Federal Energy Regulatory Commission (FERC) regulates the interstate sale and transportation of natural gas, the transmission and wholesale sales of electricity in interstate commerce, transmission access, the uniform systems of accounts, rates of depreciation and electric rates involving sales for resale.

The Nuclear Regulatory Commission (NRC) oversees the licensing, construction and operation of nuclear facilities. NRC regulations require extensive review of the safety, radiological and environmental aspects of these facilities. Periodically, the NRC requires that newly developed data and techniques be used to re-analyze the design of a nuclear power plant and, as a result, requires plant modifications as a condition of continued operation in some cases.

International Utility Regulation
The Company's consolidated and unconsolidated affiliates have locations in Argentina, Canada, Chile, Mexico, Peru and Uruguay. These operations are subject to the local, federal and other regulations of the countries in which they are located.

Other Regulation
As a trading company, Sempra Energy Trading is regulated as to its operations and its financial position. Other subsidiaries are also subject to varying amounts of regulation.

Licenses and Permits
SoCalGas and SDG&E obtain a number of permits, authorizations and licenses in connection with the transmission and distribution of natural gas. They require periodic renewal, which results in continuing regulation by the granting agency. In addition, SDG&E obtains a number of permits, authorizations and licenses in connection with the transmission and distribution of electricity. The Company's unregulated affiliates are also required to obtain permits, authorizations and licenses in the normal course of business.

Other regulatory matters are described in Note 14 of the 2000 Annual Report to Shareholders which is incorporated by reference.

SOURCES OF REVENUE

Industry segment information is contained in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 15 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

NATURAL GAS OPERATIONS

The Company purchases, sells, distributes, stores and transports natural gas. SoCalGas owns and operates a natural gas distribution, transmission and storage system that supplies natural gas to its customers (including transport to electric generating plants) throughout a 23,000-square-mile service territory from central California to the Mexican border. SDG&E purchases and distributes natural gas to 760,000 end-use customers throughout the western portion of San Diego county. SDG&E also transports gas to over 1,000 customers who procure their gas from other sources. On a smaller scale, Sempra Energy International (SEI) operates natural gas distribution systems in Mexico through 60 percent, 95 percent and 100 percent ownership of DGN-Mexicali, DGN-Chihuahua and DGN-La Laguna Durango, respectively. These North American operations are included in the following discussion of the Company's natural gas operations. SEI also has interests in natural gas operations in South America which are not consolidated and, therefore, are not included in these discussions. Additional information on international operations is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

In December 1999, Sempra Atlantic Gas (SAG), a subsidiary of SEI, was awarded a 25-year franchise by the provincial government of Nova Scotia to build and operate a natural gas distribution system in Nova Scotia. SAG has invested $23 million and plans to invest $700 million to $800 million over the next seven years to build the system, which will make natural gas available to 78 percent of the 350,000 households in Nova Scotia. Construction of the system began in the fourth quarter of 2000, with delivery of natural gas expected to begin in the second quarter of 2001.

Supplies of Natural Gas

The Company buys natural gas under several short-term and long-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. SoCalGas and SDG&E transport gas under long-term firm pipeline capacity agreements that provide for annual reservation charges. SoCalGas and SDG&E recover such fixed charges in rates. SoCalGas has firm pipeline capacity contracts with pipeline companies that expire at various dates through 2006. SDG&E has long-term capacity contracts with interstate pipelines which expire at various dates between 2007 and 2023.

Most of the natural gas purchased and delivered by the 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. These interstate companies provide transportation services for supplies purchased from other sources by the Company or its transportation customers. The rates that interstate pipeline companies may charge for natural gas and transportation services are regulated by the FERC.

The following table shows the sources of natural gas deliveries from 1996 through 2000.

	Year Ended December 31				
	2000	1999	1998	1997	1996
Purchases in billions of cubic feet					
Spot market	401	390	388	330	323
Long-term contracts	17	76	104	100	108
Total Purchases	418	466	492	430	431
Customer-owned and exchange receipts	699	574	521	514	422
Storage withdrawal (injection) - net	40	(6)	(28)	(3)	42
Company use and unaccounted for	(26)	(16)	(23)	(11)	(11)
Net Deliveries	1,131	1,018	962	930	884
Purchases in millions of dollars					
Commodity costs	$1,469	$1,084	$1,092	$1,160	$ 879
Fixed charges*	143	147	174	250	276
Total Purchases	$1,612	$1,231	$1,266	$1,410	$1,155
Average Commodity Cost of Purchases (Dollars per thousand cubic feet)	$ 3.51	$ 2.33	$ 2.22	$ 2.69	$ 2.04

* 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 SoCalGas and SDG&E.

Market-sensitive natural 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 96 percent of total natural gas volumes purchased by the Company during 2000, as compared with 91 percent and 79 percent during 1999 and 1998, respectively. Supply/demand imbalances have increased the price of natural gas in California even more than in the rest of the country because of California's dependence on natural gas fired electric generation due to air-quality considerations. The average price of natural gas at the California/Arizona (CA/AZ) border was $6.25/mmbtu in 2000, compared with $2.33/mmbtu in 1999. On December 11, 2000, the average spot cash gas price at the CA/AZ border reached a record high of $56.91/mmbtu.

During 2000, the Company delivered 1,131 bcf of natural gas through its system. Approximately 65 percent of these deliveries were customer-owned natural gas for which the Company provided transportation services. The remaining natural gas deliveries were purchased by the Company and resold to customers. The Company estimates that sufficient natural gas supplies will be available to meet the requirements of its customers for the next several years.

Customers

For regulatory purposes, customers are separated into core and noncore customers. Core customers are primarily residential and small commercial and industrial customers, without alternative fuel capability. Noncore customers consist primarily of utility electric generation (UEG), wholesale, large commercial, industrial and off-system (outside the Company's normal service territory) customers. Of the 5.8 million customer meters in the Company's service territory, only 1,600 serve the noncore market.

Most core customers purchase natural gas directly from the Company. Core customers are permitted to aggregate their natural gas requirement and, up to a limit of 10 percent of the Company's core market, to purchase natural gas directly from brokers or producers. The Company continues to be obligated to purchase reliable supplies of natural gas to serve the requirements of its core customers. SoCalGas and SDG&E recently filed an application with the CPUC to combine the two companies' core procurement portfolios.

Noncore customers have the option of purchasing natural gas either from the Company or from other sources, such as brokers or producers, for delivery through the Company's transmission and distribution system. The only natural gas supplies that the Company may offer for sale to noncore customers are the same supplies that it purchases for its core customers. Most noncore customers procure their own natural gas supply.

In 2000, for SoCalGas, 87 percent of the CPUC-authorized natural gas margin was allocated to the core customers, with 13 percent allocated to the noncore customers. In 2000, for SDG&E, 89 percent of the CPUC-authorized natural gas margin was allocated to the core customers, with 11 percent allocated to the noncore customers.

Although revenues from transportation throughput is less than for natural gas sales, the Company generally earns the same margin whether the Company buys the gas and sells it to the customer or transports natural gas already owned by the customer.

The Company also provides natural 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 natural gas on an "as available" basis, usually during the summer to reduce winter purchases when natural gas costs are generally higher. As of December 31, 2000, the Company was storing approximately 2 bcf of customer-owned gas.

Demand for Natural Gas

Natural gas is a principal energy source for residential, commercial, industrial and UEG customers. Natural gas competes with electricity for residential and commercial cooking, water heating, space heating and clothes drying, and with other fuels for large industrial, commercial and UEG uses. Growth in the natural-gas markets is largely dependent upon the health and expansion of the southern California economy. The California utilities added approximately 82,000 and 101,000 new customer meters in 2000 and 1999, respectively, representing growth rates of 1.4 percent and 1.5 percent, respectively. The Company expects its growth rate for 2001 to be at the 2000 level.

During 2000, 99 percent of residential energy customers in SoCalGas' service area used natural gas for water heating, 96 percent for space heating, 76 percent for cooking and 55 percent for clothes drying. In SDG&E's service area, 91 percent of residential energy customers used natural gas for water heating, 73 percent for space heating, 52 percent for cooking and 35 percent for clothes drying.

Demand for natural gas by noncore customers is very sensitive to the price of competing fuels. Although the number of noncore customers in 2000 was only 1,600, they accounted for approximately 11 percent of the authorized natural gas revenues and 65 percent of total natural gas volumes. External factors such as weather, the price of electricity, electric deregulation, the use of hydroelectric power, competing pipelines and general economic conditions can result in significant shifts in demand and market price. The demand for natural gas by large UEG customers is also greatly affected by the price and availability of electric power generated in other areas. The increase in UEG demand in 2000 was due to higher demand for electricity and increased use of natural gas for electric generation, a colder 2000 - 2001 winter and population growth in California. Natural gas demand in 1999 for UEG customer use increased primarily due to higher electric energy usage in the summer, as a result of warmer weather.

Effective March 31, 1998, electric industry restructuring gave California consumers the option of selecting their electric energy provider from a variety of local and out-of-state producers. As a result, natural gas demand for electric generation within southern California competes with electric power generated throughout the western United States. Although electric industry restructuring has no direct impact on the Company's natural gas operations, future volumes of natural gas transported for UEG customers may be adversely affected to the extent that regulatory changes divert electricity production from the Company's service area.

Other

Additional information concerning customer demand and other aspects of natural gas operations is provided under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 13 and 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

ELECTRIC OPERATIONS

Resource Planning

In 1996, California enacted legislation restructuring California's investor-owned electric utility industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce rates. Beginning on March 31, 1998, customers were given the opportunity to choose to continue to purchase their electricity from the local utility under regulated tariffs, to enter into contracts with other energy service providers (direct access) or to buy their power from the California Power Exchange (PX) that served as a wholesale power pool allowing all energy producers to participate competitively. However, a number of factors, including supply/demand imbalances, resulted in abnormally high wholesale electric prices beginning in mid-2000. In response to these high commodity prices, the California legislature has adopted or is proposing to adopt legislation intended to stabilize the California electric utility industry and reduce wholesale electric commodity prices.

Additional information concerning electric-industry restructuring is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 13 and 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Electric Resources

In connection with California's electric-industry restructuring, beginning March 31, 1998, the California investor-owned utilities (IOUs) were obligated to bid their power supply, including owned generation and purchased-power contracts, into the PX. The IOUs also were obligated to purchase from the PX the power that they sell. As discussed in Note 14 of the notes to Consolidated Financial Statements, due to current conditions in the California electric utility industry, the PX suspended its trading operations on January 31, 2001. SDG&E has been granted authority by the CPUC to purchase up to 1,900 megawatts of power through bilateral contracts. Also, the California legislature recently passed a bill authorizing the Department of Water Resources (DWR) to enter into long-term contracts to purchase the portion of power used by SDG&E customers that is not provided by SDG&E's existing supply. An Independent System Operator (ISO) schedules power transactions and access to the transmission system. In 1999, SDG&E completed divestiture of its owned generation other than nuclear. Based on generating plants in service and purchased-power contracts currently in place, at February 28, 2001, the megawatts (mW) of electric power available to SDG&E are as follows:

Source	mW
Nuclear generating plants	430*
Long-term contracts with other utilities	186
Contracts with others	593
Total	1,209

* Net of plants' internal usage

Natural Gas/Oil Generating Plants: In connection with electric-industry restructuring, in December 1998, SDG&E entered into agreements for the sale of its South Bay and Encina power plants and 17 combustion turbines. During the quarter ended June 30, 1999, these sales were completed for total net proceeds of $466 million. The South Bay Power Plant sale to the San Diego Unified Port District for $110 million was completed on April 23, 1999. Duke South Bay, a subsidiary of Duke Energy Power Services, will manage the plant for the Port District. The sale of the Encina Power Plant and 17 combustion-turbine generators to Dynegy Inc. and NRG Energy Inc. for $356 million was completed on May 21, 1999. SDG&E is operating and maintaining both facilities for the new owners for two years.

San Onofre Nuclear Generating Station (SONGS): SDG&E owns 20 percent of the three nuclear units at SONGS (located south of San Clemente, California). The cities of Riverside and Anaheim own a total of 5 percent of Units 2 and 3. Southern California Edison (Edison) owns the remaining interests and operates the units.

Unit 1 was removed from service in November 1992 when the CPUC issued a decision to permanently shut down the unit. At that time SDG&E began the recovery of its remaining capital investment, with full recovery completed in April 1996. The unit's spent nuclear fuel has been removed from the reactor and is stored on-site. In March 1993, the NRC issued a Possession-Only License for Unit 1, and the unit was placed in a long-term storage condition in May 1994. In June 1999, the CPUC granted authority to begin decommissioning Unit 1. Decommissioning work is now in progress.

Units 2 and 3 began commercial operation in August 1983 and April 1984, respectively. SDG&E's share of the capacity is 214 mw of Unit 2 and 216 mw of Unit 3.

During 2000, SDG&E spent $4 million on capital additions and modifications of Units 2 and 3, and expects to spend $7 million in 2001.

SDG&E deposits funds in an external trust to provide for the decommissioning of all three units.

Additional information concerning the SONGS units, nuclear decommissioning and industry restructuring (including SDG&E's divestiture of its electric generation assets) is provided below and in "Environmental Matters" and "Electric Properties" herein, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 6, 13 and 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Purchased Power: The following table lists contracts with SDG&E's various suppliers.

Supplier	Expiration Date	Megawatt Commitment	Source
Long-Term Contracts with Other Utilities:			
Portland General Electric (PGE)	December 2013	86	Coal
Public Service Company of New Mexico (PNM)	April 2001	100	System Supply
Total		186	
Other Contracts:			
QFs --			
Applied Energy	December 2019	102	Cogeneration
Yuma Cogeneration	June 2024	50	Cogeneration
Goal Line Limited Partnership	December 2025	50	Cogeneration
Other QFs (73)	Various	16	Cogeneration
		218	
Others --			
Avista Supply	December 2001	150	System Supply
PacifiCorp	December 2001	100	System Supply
Others	December 2003	125	System Supply
Total		593	

Under the contracts with PGE and PNM, SDG&E pays a capacity charge plus a charge based on the amount of energy received. Charges under these contracts are based on the selling utility's costs, including a return on and depreciation of the utility's rate base (or lease payments in cases where the utility does not own the property), fuel expenses, operating and maintenance expenses, transmission expenses, administrative and general expenses, and state and local taxes. Costs under the contracts with Qualifying Facilities are based on SDG&E's avoided cost. Charges under the remaining contracts are for firm energy only and are based on the amount of energy received. The prices under these contracts are at the market value at the time the contracts were negotiated.

Additional information concerning SDG&E's purchased-power contracts is provided below, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 13 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Power Pools

SDG&E is a participant in the Western Systems Power Pool (WSPP), which includes an electric-power and transmission-rate agreement with utilities and power agencies located throughout the United States and Canada. More than 200 investor-owned and municipal utilities, state and federal power agencies, energy brokers, and power marketers share power and information in order to increase efficiency and competition in the bulk power market. Participants are able to make power transactions on standardized terms that have been pre-approved by FERC.

Transmission Arrangements

Pacific Intertie (Intertie): The Intertie, consisting of AC and DC transmission lines, connects the Northwest with SDG&E, Pacific Gas & Electric (PG&E), Edison and others under an agreement that expires in July 2007. SDG&E's share of the Intertie is 266 mW.

Southwest Powerlink: SDG&E's 500-kilovolt Southwest Powerlink transmission line, which is shared with Arizona Public Service Company and Imperial Irrigation District, extends from Palo Verde, Arizona to San Diego. SDG&E's share of the line is 970 mW, although it can be less, depending on specific system conditions.

Mexico Interconnection: Mexico's Baja California Norte system is connected to SDG&E's system via two 230-kilovolt interconnections with firm capability of 408 mW.

Due to electric-industry restructuring (see "Transmission Access" below), the operating rights of SDG&E on these lines have been transferred to the ISO.

Transmission Access

As a result of the enactment of the National Energy Policy Act of 1992, the FERC has established rules to implement the Act's transmission-access provisions. These rules specify FERC-required procedures for others' requests for transmission service. In October 1997, the FERC approved the California IOUs' transfer of control of their transmission facilities to the ISO. On March 31, 1998, operation and control of the transmission lines was transferred to the ISO. Additional information regarding the ISO and transmission access is provided below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Fuel and Purchased-Power Costs

The following table shows the percentage of each electric-fuel source used by SDG&E and compares the costs of the fuels with each other and with the total cost of purchased power:

	Percent of kWh			Cents per kWh		
	2000	1999	1998	2000	1999	1998
Natural gas *	--	6.5%	17.3%	--	3.0	3.0
Nuclear fuel	14.9	12.6	11.5	0.5	0.5	0.6
Total generation	14.9	19.1	28.8			
Purchased power and ISO/PX	85.1	80.9	71.2	9.7	3.7	3.5
Total	100.0%	100.0%	100.0%			

* As described previously, SDG&E sold its South Bay and Encina power plants and 17 combustion turbines during the quarter ended June 30, 1999.

The cost of purchased power includes capacity costs as well as the costs of fuel. The cost of natural gas includes transportation costs. The costs of natural gas and nuclear fuel do not include SDG&E's capacity costs. While fuel costs are significantly less for nuclear units than for other units, capacity costs are higher.

Electric Fuel Supply

Natural Gas: Information concerning natural gas is provided in "Natural Gas Operations" herein.

Nuclear Fuel: The nuclear-fuel cycle includes services performed by others under contract through 2003, including mining and milling of uranium concentrate, conversion of uranium concentrate to uranium hexafluoride, enrichment services, and fabrication of fuel assemblies.

Spent fuel from Units 2 and 3 is being stored on site, where storage capacity will be adequate at least through 2005. If necessary, modifications in fuel storage technology can be implemented to provide on-site storage capacity for operation through 2022, the expiration date of the NRC operating license. Pursuant to the Nuclear Waste Policy Act of 1982, SDG&E entered into a contract with the U.S. Department of Energy (DOE) for spent-fuel disposal. Under the agreement, the DOE is responsible for the ultimate disposal of spent fuel. SDG&E pays a disposal fee of $0.99 per megawatt-hour of net nuclear generation, or approximately $3 million per year. The DOE projects it will not begin accepting spent fuel until 2010.

To the extent not currently provided by contract, the availability and the cost of the various components of the nuclear-fuel cycle for SDG&E's nuclear facilities cannot be estimated at this time.

Additional information concerning nuclear-fuel costs is provided in Note 13 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

INTERNATIONAL OPERATIONS

Sempra Energy International (SEI) develops, operates and invests in energy infrastructure projects, including natural gas distribution systems and power generation facilities, outside of the United States. SEI has interests in natural gas and/or electric generation, transmission and distribution projects in Argentina, Canada, Chile, Mexico, Peru and Uruguay, and is pursuing other projects in Latin America.

In October 2000, SEI expanded its presence in the southern portion of South America by increasing its existing investment in two Argentinean natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.) SEI increased its investment from 21.5 percent to 43 percent by purchasing additional interests for $147 million. In June 1999, the company contributed capital to the Argentinean companies to retire $32 million of debt. The distribution companies serve 1.3 million customers in central and southern Argentina, respectively, and have a combined throughput of 650 million cubic feet per day.

In June 2000, SEI, PG&E Corporation and Proxima Gas S.A de C.V announced a joint agreement to construct a $230 million, 215-mile natural gas pipeline that will extend from Arizona to Rosarito, Baja California. The pipeline, which will have the capacity to transport 500 million cubic feet of natural gas per day, will connect SEI's current natural gas assets in Mexicali and Rosarito. Construction of the pipeline is anticipated to begin in early 2002. Agreements have been signed for more than half of the capacity on the pipeline, with natural gas expected to begin flowing by September 2002.

In June 1999, SEI and Public Service Enterprise Group (PSEG) announced the completion of the joint purchase of 90 percent of Chilquinta Energia S.A. (Energia). In January 2000, SEI and PSEG purchased an additional 9.75 percent of Energia, increasing their joint and equal holdings to 99.98 percent. In September 1999, SEI and PSEG completed their acquisition of 47.5 percent of the outstanding shares of Luz del Sur S.A.A., a Peruvian Electric Company. This acquisition, combined with the 37 percent already owned through Energia, increased the companies' total joint and equal ownership to 84.5 percent of Luz del Sur S.A.A.

SEI owns 60 percent of Distribuidora de Gas Natural de Mexicali, S. de R.L. de C.V. (DGN-Mexicali), a Mexican company that holds the first license awarded to a private company to build a natural gas distribution system in Mexico. On August 20, 1997, DGN-Mexicali began to deliver natural gas to customers in Mexicali, Baja California. It will invest up to $25 million to provide service to 25,000 customers during the first five years of operation, of which $18 million has been invested as of December 31, 2000.

SEI owns 95 percent of Distribuidora de Gas Natural de Chihuahua, S. de R.L. de C.V. (DGN-Chihuahua), which distributes natural gas to the city of Chihuahua, Mexico and surrounding areas. On July 9, 1997, it acquired ownership of a 16-mile transmission pipeline serving 20 industrial customers. SEI will invest nearly $50 million to provide service to 50,000 customers in the first five years of operation, of which $38 million has been invested as of December 31, 2000.

In December 1999, Sempra Atlantic Gas (SAG), a subsidiary of SEI, was awarded a 25-year franchise by the provincial government of Nova Scotia to build and operate a natural gas distribution system in Nova Scotia. Construction began in the fourth quarter of 2000, with service to customers expected to begin in the second quarter of 2001. SAG plans to invest $700 to $800 million over the next seven years in building a system that will make gas available to 78 percent of the 350,000 households in Nova Scotia.

In May 1999, SEI was awarded a 30-year license to build and operate a natural gas distribution system in the La Laguna-Durango zone in north-central Mexico. The La Laguna-Durango region has a population of 1.1 million and is home to a number of energy-intensive industries. SEI's subsidiary, DGN De La Laguna Durango, has invested $18 million through 2000 and will have invested over $40 million to serve an estimated 50,000 customers by the fifth year of operation.

In August 1998, SEI was awarded a 10-year agreement by the Mexican Federal Electric Commission to provide a complete energy-supply package for a power plant in Rosarito, Baja California. The contract includes provisions for delivery of up to 300 million cubic feet per day of natural gas, the related transportation services in the U.S., and construction of a 23-mile pipeline from the U.S.-Mexico border to the plant. Construction of the pipeline was completed in mid-2000 at a cost of $38 million, and SEI began flowing gas to the power plant in July 2000. The pipeline will also serve as a link for a natural gas distribution system in Tijuana, Baja California, between San Diego and Rosarito.

In May 1998, PE was awarded a concession by the government of Uruguay to build separate natural gas and propane distribution systems to serve most of the country, excluding Montevideo. The consortium began providing natural gas service in mid-2000. The $160-million project will serve an estimated 250,000 customers by 2005.

In February 2001, SEI announced plans to construct a $350 million, 600-megawatt power plant near Mexicali, Mexico. Fuel for the natural gas fired plant will be supplied through the Arizona to Rosarito pipeline discussed above. Construction of the project, named Termoelectrica de Mexicali, is expected to begin in mid-2001, with completion anticipated by mid-2003.

Net income for international operations in 2000 was $33 million compared to net income of $2 million and a net loss of $4 million for 1999 and 1998, respectively. The Company's international business unit includes the results of the investments, joint ventures and projects outside of the United States, as well as the results of similar, smaller operations in the eastern United States.

Additional information on international operations is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 3 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

SEMPRA ENERGY TRADING (SET)

SET, a leading natural gas and power marketing firm headquartered in Stamford, Connecticut, was acquired on December 31, 1997. In July 1998, SET purchased a wholesale trading and commercial marketing subsidiary of Consolidated Natural Gas for $36 million to expand its operation in the eastern United States. In addition to its domestic operations, SET has operations in Canada, Europe, and Asia.

SET derives a substantial portion of its revenue from market making and trading activities, as a principal, in natural gas, petroleum and electricity. It quotes bid and offer prices to end users and other market makers. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. In addition, SET takes positions in energy markets based on the expectation of future market conditions.

In April 2000, SET invested $4 million in Utility.com, the world's first Internet utility company. Utility.com is currently registered to provide electricity in 10 states. The company provides long-distance telephone service in 41 states, DSL service to major metropolitan areas in 29 states and Internet access to customers throughout the continental United States.

For the year ended December 31, 2000, SET recorded operating revenues of $795 million and net income of $155 million, compared to operating revenues of $450 million and net income of $19 million in 1999.

Additional information on SET is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 3, 10 and 15 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

SEMPRA ENERGY RESOURCES (SER)

SER develops power plants for the competitive market, as well as owning natural gas storage, production and transportation facilities. SER is planning to develop 5,000-10,000 megawatts of generation within the next decade in the Southwest, the Northeast, the Gulf States and the Midwest. SER is a 50-percent partner in El Dorado Energy, a 500-megawatt power plant located near Las Vegas, Nevada, which began commercial operation in 2000.

In December 2000, SER obtained approval from the California Energy Commission to construct the Elk Hills Power Project, a $360 million, 550-megawatt power plant near Bakersfield, California. Construction of the power plant, which is being developed jointly with Occidental Energy Ventures Corporation, is scheduled to begin in the second quarter of 2001. The power plant, which is expected to be operational in 2002, will generate energy for approximately 350,000 households.

Also in December 2000, SER obtained approval from Arizona's Maricopa County for construction of a $630 million, 1200-megawatt power plant. Mesquite Power will be located 40 miles west of Phoenix, Arizona, and will produce energy for up to 700,000 homes. It is anticipated that construction on the plant will begin in the second quarter of 2001, with completion expected during 2003.

SER recorded net income of $33 million, $5 million and $8 million in 2000, 1999 and 1998, respectively.

Additional information is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 3 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

RATES AND REGULATION--CALIFORNIA UTILITIES

The Company's principal subsidiaries, SoCalGas and SDG&E, are regulated by the 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. The regulatory structure is complex and has a substantial impact on the profitability of the Company. Both the electric and natural gas industries are currently undergoing transitions to competition and are being impacted by abnormally high commodity prices resulting from supply/demand imbalances.

Electric Industry Restructuring

A flawed electric-industry restructuring plan, electricity supply/demand imbalances and legislative and regulatory responses significantly impact the Company's operations. Additional information on electric-industry restructuring is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Natural Gas Industry Restructuring

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. The CPUC is currently assessing the current market and regulatory framework for California's natural gas industry. Supply/demand imbalances are affecting the price of natural gas in California more than in the rest of the country because of California's dependence on natural gas fired electric generation due to air-quality considerations. Additional information on natural gas industry restructuring is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Balancing Accounts

In general, earnings fluctuations from changes in the costs of natural gas and consumption levels for the majority of natural gas are eliminated through balancing accounts authorized by the CPUC. As a result of California's electric restructuring law, overcollections recorded in the electric balancing accounts were applied to transition cost recovery, and fluctuations in certain costs and consumption levels can now affect earnings from electric operations. Additional information on balancing accounts is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 2 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Performance-Based Regulation (PBR)

In recent years, the CPUC has directed utilities to use PBR. To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, PBR has replaced the general rate case and certain other regulatory proceedings for both SoCalGas and SDG&E. Additional information on PBR is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Biennial Cost Allocation Proceeding (BCAP)

Rates to recover the changes in the cost of natural gas transportation services are determined in the BCAP. The BCAP adjusts rates to reflect variances in customer demand from estimates previously used in establishing customer natural gas transportation rates. The mechanism substantially eliminates the effect on income of variances in market demand and natural gas transportation costs and, for SoCalGas, is subject to the limitations of the Gas Cost Incentive Mechanism (GCIM) described below. The BCAP will continue under PBR. Additional information on the BCAP is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Gas Cost Incentive Mechanism (GCIM)

The GCIM is a process SoCalGas uses to evaluate its natural gas purchases, substantially replacing the previous process of reasonableness reviews. Additional information on the GCIM is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Cost of Capital

Under PBR, annual Cost of Capital proceedings have been replaced by an automatic adjustment mechanism if changes in certain indices exceed established tolerances. Additional information on the utilities' cost of capital is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 14 of the notes to Consolidated Financial Statements of the 2000 Annual Report to Shareholders, which is incorporated by reference.

ENVIRONMENTAL MATTERS

Discussions about environmental issues affecting the Company are included in "Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2000 Annual Report to Shareholders, which is incorporated by reference. The following additional information should be read in conjunction with those discussions.

Hazardous Substances

In 1994, the CPUC approved the Hazardous Waste Collaborative Memorandum account, a mechanism that allows SoCalGas, SDG&E and other utilities to recover in rates the costs associated with the cleanup of sites contaminated with hazardous waste. In general, utilities are allowed to recover 90 percent of their cleanup costs and any related costs of litigation. In early 1998, the CPUC modified this mechanism to exclude these costs related to electric generation activities. These costs are now eligible for inclusion in the competition transition cost recovery process. The effect of this decision is that SDG&E's costs of compliance with environmental regulations may not be fully recoverable if they exceed the estimates included in the transaction costs (see "Electric Resources" above).

During the early 1900s, SDG&E, SoCalGas and their predecessors manufactured gas from coal or oil. The manufacturing sites often have become contaminated with the hazardous residual by-products of the process. SDG&E has identified three former manufactured-gas plant sites. All three sites have been remediated and closure letters received for two sites. At December 31, 2000 estimated remaining remediation liability on these sites is less than $300,000. In addition, SoCalGas has identified 42 former manufactured-gas plant sites at which it (together with other users as to 21 of these sites) may have cleanup obligations. As of December 31, 2000, 18 of these sites have been remediated, of which 14 have received certification from the California Environmental Protection Agency. Preliminary investigations, at a minimum, have been completed on 40 of the sites. At December 31, 2000, SoCalGas' estimated remaining investigation and remediation liability for all of these sites is $57.6 million.

Cleanup of SDG&E's Station B, a steam and electric generating facility operated in San Diego between 1911 and 1993, was completed during 1999. Activities included removal of asbestos and lead-based paint and the removal or cleanup of other substances. The sale of the facility was completed in December 1999.

SDG&E sold the South Bay and Encina power plants and 17 combustion turbines in 1999. SDG&E conducted a thorough environmental assessment of the power plants and combustion turbine sites. Pursuant to the sale agreements, SDG&E and the buyers have apportioned responsibility for remediation obligations for contamination existing on these sites. Estimated costs to perform the necessary remediation at all sites are approximately $10 million. Together with other appropriate costs, these costs were offset against the sales price for the facilities and the remaining net proceeds were offset against SDG&E's other transition costs. Remediation of the plants commenced in early 2001; completion is expected in mid-2001.

SDG&E and SoCalGas lawfully disposed of wastes at permitted facilities owned and operated by other entities. Operations at these facilities may result in actual or threatened risks to the environment or public health. Under California law, businesses that arrange for legal disposal of wastes at a permitted facility from which wastes are later released, or threaten to be released, can be held financially responsible for corrective actions at the facility.

The Company and other subsidiaries have been named as potentially responsible parties (PRPs) for two landfill sites and six industrial waste disposal sites, from which releases have occurred as described below.

Remedial actions and negotiations with other PRPs and the United States Environmental Protection Agency (EPA) have been in progress since 1986 and 1993 for the two landfill sites. The Company's share of costs to remediate these sites is estimated to be $3.7 million, of which $410,000 was incurred during 2000.

In the early 1990s, the Company was notified of hazards at two industrial waste treatment facilities in the California communities of Fresno and Carson, where the Company had disposed of wastes. During 2000, the Company settled with the other PRPs at these sites for $425,000 and has no additional liability.

The Company and 10 other entities have been named PRPs by the Department of Toxic Substance Control (DTSC) as liable for any required corrective action regarding contamination at an industrial waste disposal site in Pico Rivera, California. DTSC has taken this action because SDG&E and others sold used transformers to the site's owner. SDG&E and the other PRPs have entered into a cost-sharing agreement to provide funding for the implementation of a consent order between DTSC and the site owner for the development of a cleanup plan. SDG&E's interim share under the agreement is 10.1 percent, subject to adjustment based on ultimate responsibility allocations. The total estimate for all PRPs is $3 million to $9 million for the development of the cleanup plan and the actual cleanup.

In December 1999, SoCalGas was notified that it is a PRP at a waste treatment facility in Bakersfield, California. SoCalGas is working with other PRPs in order to remove from the site certain liquid wastes that threaten to be released. It is too early to determine the existence or extent of any prior releases or the Company's potential total liability.

In March 2000, SoCalGas was notified it is a PRP at a former mercury recycling facility in Brisbane, California. Total potential liability is estimated at less than $10,000. Also in March 2000, SoCalGas was sued in Federal District Court as a PRP in a waste oil disposal site in Los Angeles. Plaintiffs alleged that SoCalGas had transported various petroleum wastes to the site in the 1950s for recycling. SoCalGas settled with plaintiffs in December 2000 for $200,000.

At December 31, 2000, the Company's estimated remaining investigation and remediation liability related to hazardous waste sites, including the manufactured gas sites, was $59 million, of which 90 percent is authorized to be recovered through the Hazardous Waste Collaborative mechanism. This estimated cost excludes remediation cost associated with the sale of the electric-generation plants and the 17 combustion turbines. The Company believes that any costs not ultimately recovered through rates, insurance or other means, 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 Hazardous Waste Collaborative mechanism are recorded as a regulatory asset.

Electric and Magnetic Fields (EMFs)
Although scientists continue to research the possibility that exposure to EMFs causes adverse health effects, science has not demonstrated a cause-and-effect relationship between adverse health effects and exposure to the type of EMFs emitted by power lines and other electrical facilities. Some laboratory studies suggest that such exposure creates biological effects, but those effects have not been shown to be harmful. The studies that have most concerned the public are epidemiological studies, some of which have reported a weak correlation between childhood leukemia and the proximity of homes to certain power lines and equipment. Other epidemiological studies found no correlation between estimated exposure and any disease. Scientists cannot explain why some studies using estimates of past exposure report correlations between estimated EMF levels and disease, while others do not.

To respond to public concerns, the CPUC has directed California utilities to adopt a low-cost EMF-reduction policy that requires reasonable design changes to achieve noticeable reduction of EMF levels that are anticipated from new projects. However, consistent with the major scientific reviews of the available research literature, the CPUC has indicated that no health risk has been identified.

Air and Water Quality
California's air quality standards are more restrictive than federal standards. However, as a result of the sale of the Company's fossil-fuel power plants and combustion turbines, the Company's primary air-quality issue, compliance with these standards has less significance to the Company's operation.

The transmission and distribution of natural gas require the operation of compressor stations, which are subject to increasingly stringent air-quality standards. Costs to comply with these standards are recovered in rates.

In connection with the issuance of operating permits, SDG&E and the other owners of SONGS reached agreement with the California Coastal Commission to mitigate the environmental damage to the marine environment attributed to the cooling-water discharge from SONGS Units 2 and 3. This mitigation program includes an enhanced fish-protection system, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands. In addition, the owners must deposit $3.6 million with the state for the enhancement of fish hatchery programs and pay for monitoring and oversight of the mitigation projects. SDG&E's share of the cost is estimated to be $27.4 million. The pricing structure contained in the CPUC's decision regarding accelerated recovery of SONGS Units 2 and 3 (described in "Electric Resources" above) is expected to accommodate these added mitigation costs.

OTHER MATTERS

Research, Development and Demonstration (RD&D)

The SoCalGas RD&D portfolio is focused in five major areas: operations, utilization systems, power generation, public interest and transportation. Each of these activities provides benefits to customers and society by providing more cost-effective, efficient natural gas equipment with lower emissions, increased safety, and reduced environmental mitigation and other operating costs. The CPUC has authorized SoCalGas to recover its operating costs associated with RD&D. SoCalGas' annual RD&D costs have averaged $7.9 million over the past three years.

For 2000, the CPUC authorized SDG&E to fund $1.2 million and $4.2 million for its gas and electric RD&D programs, respectively, which includes $3.9 million to the CEC for its PIER (Public Interest Energy Research) program. SDG&E co-funded several of these projects with the CEC. Annual RD&D costs have averaged $4.5 million over the past three years.

Employees of Registrant

As of December 31, 2000 the Company had 11,232 employees, compared to 11,248 at December 31, 1999.

Wages

SoCalGas and SDG&E employ over 9,000 persons. Field, technical and most clerical employees at SoCalGas are represented by the Utility Workers' Union of America or the International Chemical Workers' Council. The collective bargaining agreement on wages, hours and working conditions remains in effect through March 31, 2002. Certain employees at SDG&E are represented by the Local 465 International Brotherhood of Electrical Workers under two labor agreements. The current generation contract runs through May 25, 2001. The transmission and distribution contract runs through August 31, 2001.

ITEM 2. PROPERTIES

Electric Properties

The Company's generating capacity is described in "Electric Resources" herein.

The Company's electric transmission and distribution facilities include substations, and overhead and underground lines. Periodically, various areas of the service territory require expansion to handle customer growth.

Natural Gas Properties

At December 31, 2000, the Company owned approximately 3,017 miles of transmission and storage pipeline, 52,218 miles of distribution pipeline and 50,406 miles of service piping. It also owned 12 transmission compressor stations and 6 underground storage reservoirs (with a combined working capacity of 117.8 Bcf).

Other Properties

The 21-story corporate headquarters building at 101 Ash Street, San Diego is occupied pursuant to a capital lease with an original term through 2005. The lease has four separate five-year renewal options.

SoCalGas has a 15-percent limited partnership interest in a 52-story office building in downtown Los Angeles. SoCalGas leases approximately half of the building through 2011. The lease has six separate five-year renewal options.

SDG&E occupies an office complex at Century Park Court in San Diego pursuant to an operating lease ending in 2007. The lease can be renewed for two five-year periods.

The Company owns or leases other offices, operating and maintenance centers, shops, service facilities and equipment necessary in the conduct of business.

ITEM 3. LEGAL PROCEEDINGS

Except for the matters referred to in the financial statements incorporated by reference in Item 8 or referred to elsewhere in this Annual Report, neither Sempra Energy nor its subsidiaries are 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

None

PART II

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

Common stock of Sempra Energy is traded on the New York and Pacific stock exchanges. At January 31, 2001, there were approximately 75,000 holders of record of the Company's common stock. The quarterly common stock information, required by Item 5 is included in the schedule of Quarterly Financial Data of the 2000 Annual Report to Shareholders, which is incorporated by reference.

Dividend Restrictions
CPUC regulation of the utilities' capital structure limits to $924 million the portion of the Company's December 31, 2000 retained earnings that is available for dividends. Additional information is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2000 Annual Report to Shareholders, which is incorporated by reference.

ITEM 6. SELECTED FINANCIAL DATA

(Dollars in millions)	2000	1999	1998	1997	1996
	At December 31, or for the years then ended				
Income Statement Data:					
Revenues and other income	$ 7,143	$ 5,410	$ 4,996	$ 5,108	$ 4,520
Income before interest and income taxes	$ 985	$ 802	$ 629	$ 927	$ 927
Net income	$ 429	$ 394	$ 294	$ 432	$ 427
Balance Sheet Data:					
Total assets	$15,612	$11,124	$10,456	$10,756	$ 9,762
Long-term debt	$ 3,268	$ 2,902	$ 2,795	$ 3,175	$ 2,704
Short-term debt (a)	$ 936	$ 337	$ 373	$ 624	$ 481
Shareholders' equity	$ 2,494	$ 2,986	$ 2,913	$ 2,959	$ 2,930
Per Common Share Data:					
Net income					
Basic	$ 2.06	$ 1.66	$ 1.24	$ 1.83	$ 1.77
Diluted	$ 2.06	$ 1.66	$ 1.24	$ 1.82	$ 1.77
Dividends declared	$ 1.00	$ 1.56	$ 1.56	$ 1.27	$ 1.24
Book value	$ 12.35	$ 12.58	$ 12.29	$ 12.56	$ 12.21

(a) Includes long-term debt due within one year.

This data should be read in conjunction with the Consolidated Financial Statements and the notes to Consolidated Financial Statements contained in the 2000 Annual Report to Shareholders, which is incorporated by reference.

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

The information required by Item 7 is incorporated by reference from pages 22 through 37 of the 2000 Annual Report to Shareholders.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by Item 7A is incorporated by reference from pages 35 through 37 of the 2000 Annual Report to Shareholders.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by Item 8 is incorporated by reference from pages 40 through 78 of the 2000 Annual Report to Shareholders. Item 14(a)1 includes a listing of financial statements included in the 2000 Annual Report to Shareholders.

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

The information required on Identification of Directors is incorporated by reference from "Election of Directors" in the Proxy Statement prepared for the May 2001 annual meeting of shareholders. The information required on the Company's executive officers is provided below.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age*	Position
Stephen L. Baum	59	Chairman of the Board, Chief Executive Officer and President
Donald E. Felsinger	53	Group President, Sempra Energy Global Enterprises
Edwin A. Guiles	51	Group President, Regulated Business Units
John R. Light	59	Executive Vice President and General Counsel
Neal E. Schmale	54	Executive Vice President and Chief Financial Officer
Darcel L. Hulse	53	Senior Vice President
Frederick E. John	54	Senior Vice President, External Affairs
Margot A. Kyd	47	Senior Vice President, Chief Administrative and Environmental Officer
G. Joyce Rowland	46	Senior Vice President, Human Resources and Chief Ethics Officer
Frank H. Ault	56	Vice President and Controller

* As of December 31, 2000.

Each Executive Officer has been an officer of the Company or one of its subsidiaries for more than five years, with the exception of Mssrs. Hulse, Light and Schmale. Prior to joining the Company in 1999, Mr. Hulse was President of Unocal Asia-Pacific Ventures. Prior to joining the Company in 1998, Mr. Light was a partner in the law firm of Latham & Watkins. Prior to joining the Company in 1997, Mr. Schmale was Chief Financial Officer of Unocal Corporation.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference from "Election of Directors" and "Executive Compensation" in the Proxy Statement prepared for the May 2001 annual meeting of shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 is incorporated by reference from "Election of Directors" in the Proxy Statement prepared for the May 2001 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.
None.

PART IV

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

(a) The following documents are filed as part of this report:

1. Financial statements

*Incorporated by reference from the indicated pages of the 2000 Annual Report to Shareholders.

2. Financial statement schedules

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

Any other schedules for which provision is made in Regulation S-X are not required under the instructions contained therein or are inapplicable.

3. Exhibits

See Exhibit Index on page 34 of this report.

(b) Reports on Form 8-K

The following reports on Form 8-K were filed after September 30, 2000:

Current Report on Form 8-K filed October 27, 2000, filing as an exhibit the Company's press release of October 26, 2000 giving the financial results for the three-month period ended September 30, 2000.

Current Report on Form 8-K filed December 5, 2000, announcing distribution of a Preliminary Prospectus Supplement related to the offering of $300 million of notes by Sempra Energy.

Current Report on Form 8-K filed December 13, 2000, announcing the execution of an underwriting agreement for the issuance of $300 million of notes by Sempra Energy.

Current Report on Form 8-K filed January 24, 2001, announcing SDG&E's application to the CPUC for authority to implement an electric rate surcharge, which would increase the rates it may charge its electric customers.

Current Report on Form 8-K filed January 30, 2001, filing as an exhibit the Company's press release of January 25, 2001 giving the financial results for the year ended December 31, 2000.

Current Report on Form 8-K filed February 16, 2001, reporting a discussion of recent developments affecting SDG&E contained in supplemental information distributed in connection with the remarketing from short term to long term of certain unsecured, variable-rate SDG&E bonds.

INDEPENDENT AUDITORS' CONSENT AND REPORT ON SCHEDULE

To the Board of Directors and Shareholders of Sempra Energy:

We consent to the incorporation by reference in Registration Statement Numbers 333-51309, 333-52192 and 333-77843 on Form S-3 and Registration Statement Numbers 333-56161, 333-50806 and 333-49732 on Form S-8 of Sempra Energy of our report dated January 26, 2001 (February 27, 2001 as to Notes 3,4,5 and 14), incorporated by reference in this Annual Report on Form 10-K of Sempra Energy for the year ended December 31, 2000.

Our audits of the financial statements referred to in our aforementioned report also included the financial statement schedule of Sempra Energy listed in Item 14. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
March 9, 2001

Schedule I -- CONDENSED FINANCIAL INFORMATION OF PARENT

SEMPRA ENERGY

Condensed Statement of Income
(Dollars in millions, except per share amounts)

For the year ended December 31	2000	1999	1998
Other income	$ 52	$ 37	$ --
Interest expense	(152)	(40)	(1)
Operating expenses and income tax benefits	(19)	(10)	(9)
Loss before subsidiary earnings	(119)	(13)	(10)
Subsidiary earnings	548	407	304
Net income	$ 429	$ 394	$ 294
Average common shares outstanding (basic)	208,155	237,245	236,423
Average common shares outstanding (diluted)	208,345	237,553	237,124
Net income per common share (basic)	$ 2.06	$ 1.66	$ 1.24
Net income per common share (diluted)	$ 2.06	$ 1.66	$ 1.24

Condensed Balance Sheet
(Dollars in millions)

Balance at December 31	2000	1999
Assets:		
Cash and cash equivalents	$ 63	$ --
Due from affiliates	656	774
Other current assets	3	11
Total current assets	722	785
Investments in subsidiaries	4,220	3,828
Other assets	308	167
Total Assets	$ 5,250	$ 4,780
Liabilities and Shareholders' Equity:		
Dividends payable	$ 50	$ 94
Due to affiliates	1,056	881
Other current liabilities	514	191
Total current liabilities	1,620	1,166
Long-term debt	1,006	138
Loan payable to SDG&E	--	422
Other long-term liabilities	130	68
Common equity	2,494	2,986
Total Liabilities and Shareholders' Equity	$ 5,250	$ 4,780

SEMPRA ENERGY

Condensed Statement of Cash Flows
(Dollars in millions)

For the year ended December 31	2000	1999	1998
Cash flows from operating activities	$ 74	$ 64	$ 71
Common stock dividends	(244)	(368)	(94)
Repurchase of common stock	(725)	--	--
Sale of common stock	12	3	4
Issuances of long-term debt	1,000	--	--
Payment on long-term debt	(1)	--	--
Loans from (payments to) affiliates - net	(220)	695	--
Cash provided by (used in) financing activities	(178)	330	(90)
Dividends received from subsidiaries	250	100	130
Expenditures for property, plant and equipment	(58)	(86)	(44)
Increase in investments and other assets	(25)	(475)	--
Cash provided by (used in) investing activities	167	(461)	86
Net cash flow	63	(67)	67
Cash and cash equivalents, beginning of year	--	67	--
Cash and cash equivalents, end of year	$ 63	$ --	$ 67

Supplemental Disclosure of Cash Flow Information:

Property dividends received from subsidiaries	$ 5	$ 2	$ 56

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, hereunto duly authorized.

SEMPRA ENERGY

By: /s/ Stephen L. Baum

Stephen L. Baum
Chairman, Chief Executive Officer
and President

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

Name/Title	Signature	Date
Principal Executive Officer: Stephen L. Baum Chairman, Chief Executive Officer and President	/s/ Stephen L. Baum	March 6, 2001
Principal Financial Officer: Neal E. Schmale Executive Vice President, Chief Financial Officer	/s/ Neal E. Schmale	March 6, 2001
Principal Accounting Officer: Frank H. Ault Vice President and Controller	/s/ Frank H. Ault	March 6, 2001
Directors: Stephen L. Baum, Chairman	/s/ Stephen L. Baum	March 6, 2001
Hyla H. Bertea, Director	/s/ Hyla H. Bertea	March 6, 2001
Ann L. Burr, Director	/s/ Ann L. Burr	March 6, 2001
Herbert L. Carter, Director	/s/ Herbert L. Carter	March 6, 2001
Richard A. Collato, Director	/s/ Richard A. Collato	March 6, 2001
Daniel W. Derbes, Director	/s/ Daniel W. Derbes	March 6, 2001
Wilford D. Godbold, Jr., Director	/s/ Wilford D. Godbold, Jr.	March 6, 2001
William D. Jones, Director	/s/ William D. Jones	March 6, 2001
Ralph R. Ocampo, Director	/s/ Ralph R. Ocampo	March 6, 2001
William G. Ouchi, Director	/s/ William G. Ouchi	March 6, 2001
Richard J. Stegemeier, Director	/s/ Richard J. Stegemeier	March 6, 2001
Thomas C. Stickel, Director	/s/ Thomas C. Stickel	March 6, 2001
Diana L. Walker, Director	/s/ Diana L. Walker	March 6, 2001

EXHIBIT INDEX

The Forms 8, 8-B/A, 8-K, S-4, 10-K and 10-Q referred to herein were filed under Commission File Number 1-40 (Pacific Enterprises), Commission File Number 1-3779 (San Diego Gas & Electric), Commission File Number 1-1402 (Southern California Gas Company), Commission File Number 1-11439 (Enova Corporation) and/or Commission File Number 333-30761 (SDG&E Funding LLC).

3.a The following exhibits relate to Sempra Energy and its subsidiaries

Exhibit 1 -- Underwriting Agreements

Enova Corporation and San Diego Gas & Electric Company (SDG&E)
- --

1.01 Underwriting Agreement dated December 4, 1997 (Incorporated by reference from Form 8-K filed by SDG&E Funding LLC on December 23, 1997 (Exhibit 1.1)).

Exhibit 3 -- Bylaws and Articles of Incorporation

Bylaws

Sempra Energy
- -------------

3.01 Amended and Restated Bylaws of Sempra Energy effective May 26, 1998 (Incorporated by reference from the Registration Statement on Form S-8 Sempra Energy Registration No. 333-56161 dated June 5, 1998 (Exhibit 3.2)).

Articles of Incorporation

Sempra Energy
- -------------

3.02 Amended and Restated Articles of Incorporation of Sempra Energy (Incorporated by reference to the Registration Statement on Form S-3 File No. 333-51309 dated April 29, 1998, Exhibit 3.1).

Exhibit 4 -- Instruments Defining the Rights of Security Holders, Including Indentures

The Company agrees to furnish a copy of each such instrument to the Commission upon request.

Enova Corporation and San Diego Gas & Electric Company (SDG&E)
- --

4.01 Mortgage and Deed of Trust dated July 1, 1940. (Incorporated by reference from SDG&E Registration No. 2-49810, Exhibit 2A.)

4.02 Second Supplemental Indenture dated as of March 1, 1948. (Incorporated by reference from SDG&E Registration No. 2-49810, Exhibit 2C.)

4.03 Ninth Supplemental Indenture dated as of August 1, 1968. (Incorporated by reference from SDG&E Registration No. 2-68420, Exhibit 2D.)

4.04 Tenth Supplemental Indenture dated as of December 1, 1968. (Incorporated by reference from SDG&E Registration No. 2-36042, Exhibit 2K.)

4.05 Sixteenth Supplemental Indenture dated August 28, 1975. (Incorporated by reference from SDG&E Registration No. 2-68420, Exhibit 2E.)

4.06 Thirtieth Supplemental Indenture dated September 28, 1983. (Incorporated by reference from SDG&E Registration No. 33-34017, Exhibit 4.3.)

Pacific Enterprises/Southern California Gas
- ---

4.07 First Mortgage Indenture of Southern California Gas Company to American Trust Company dated as of October 1, 1940 (Registration Statement No. 2-4504 filed by Southern California Gas Company on September 16, 1940; Exhibit B-4).

4.08 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of July 1, 1947 (Registration Statement No. 2-7072 filed by Southern California Gas Company on March 15, 1947; Exhibit B-5).

4.09 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of August 1, 1955 (Registration Statement No. 2-11997 filed by Pacific Lighting Corporation on October 26, 1955; Exhibit 4.07).

4.10 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of June 1, 1956 (Registration Statement No. 2-12456 filed by Southern California Gas Company on April 23, 1956; Exhibit 2.08).

4.11 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of August 1, 1972 (Registration Statement No. 2-59832 filed by Southern California Gas Company on September 6, 1977; Exhibit 2.19).

4.12 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of May 1, 1976 (Registration Statement No. 2-56034 filed by Southern California Gas Company on April 14, 1976; Exhibit 2.20).

4.13 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of September 15, 1981 (Pacific Enterprises 1981 Form 10-K; Exhibit 4.25).

4.14 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 (Southern California Gas Company 1984 Form 10-K; Exhibit 4.29).

4.15 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 (Pacific Enterprises 1987 Form 10-K; Exhibit 4.11).

4.16 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 (Registration Statement No. 33-50826 filed by Southern California Gas Company on August 13, 1992; Exhibit 4.37).

Exhibit 10 -- Material Contracts (Previously filed exhibits are incorporated by reference from Forms 8-K, S-4, 10-K or 10-Q as referenced below).

Sempra Energy
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10.01 Amendment to Employment Agreement, effective December 1, 1998. (Employment agreement, dated as of October 12, 1996 between Mineral Energy Company and Stephen L. Baum (Enova 8-K filed October 15, 1996, Exhibit 10.2))

10.02 Amendment to Employment Agreement effective December 1, 1998. (Employment contract dated as of October 12, 1996 between Mineral Energy Company and Richard D. Farman (Enova 8-K filed October 15, 1996, Exhibit 10.3))

10.03 Amendment to Employment Agreement effective December 1, 1998. (Employment contract, dated as of October 12, 1996 between Mineral Energy Company and Donald E. Felsinger (Enova 8-K filed October 15, 1996, Exhibit 10.4))

10.04 Amendment to Employment Agreement effective December 1, 1998. (Employment contract, dated as of October 12, 1996 between Mineral Energy Company and Warren I. Mitchell (Enova 8-K filed October 15, 1996, Exhibit 10.5))

Enova Corporation and San Diego Gas & Electric Company (SDG&E)
- ---

10.05 Transition Property Purchase and Sale Agreement dated December 16, 1997 (Incorporated by reference from Form 8-K filed by SDG&E Funding LLC on December 23, 1997 (Exhibit 10.1)).

10.06 Transition Property Servicing Agreement dated December 16, 1997 (Incorporated by reference from Form 8-K filed by SDG&E Funding LLC on December 23, 1997 (Exhibit 10.2)).

Compensation

Sempra Energy
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10.07 Sempra Energy Deferred Compensation and Excess Savings Plan effective January 1, 2000.

10.08 Sempra Energy Supplemental Executive Retirement Plan as amended and restated effective July 1, 1998 (1998 Form 10-K Exhibit 10.09).

10.09 Sempra Energy Deferred Compensation Agreement for Directors effective June 1, 1998 (1998 Form 10-K Exhibit 10.10).

10.10 Sempra Energy Executive Incentive Plan effective June 1, 1998 1998 Form 10-K Exhibit 10.11).

10.11 Sempra Energy Executive Deferred Compensation Agreement effective June 1, 1998 (1998 Form 10-K Exhibit 10.12).

10.12 Sempra Energy Retirement Plan for Directors effective June 1, 1998 (1998 Form 10-K Exhibit 10.13).

10.13 Sempra Energy 1998 Long Term Incentive Plan (Incorporated by reference from the Registration Statement on Form S-8 Sempra Energy Registration No. 333-56161 dated June 5, 1998 (Exhibit 4.1)).

10.14 Sempra Energy 1998 Non-Employee Directors' Stock Plan (Incorporated by reference from the Registration Statement on Form S-8 Sempra Energy Registration No. 333-56161 dated June 5, 1998 (Exhibit 4.2)).

San Diego Gas & Electric (SDG&E)
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10.15 Supplemental Executive Retirement Plan restated as of July 1, 1994 (1994 SDG&E Form 10-K Exhibit 10.14).

Pacific Enterprises/Southern California Gas Company
- ---

10.16 Pacific Enterprises Employee Stock Ownership Plan and Trust Agreement as amended effective October 1, 1992 (Pacific Enterprises 1992 Form 10-K Exhibit 10.18).

Financing

Enova Corporation and San Diego Gas & Electric (SDG&E)
- --

10.17 Loan agreement with the City of Chula Vista in connection with the issuance of $25 million of Industrial Development Bonds, dated as of October 1, 1997 (Enova 1997 Form 10-K Exhibit 10.34).

10.18 Loan agreement with the City of Chula Vista in connection with the issuance of $38.9 million of Industrial Development Bonds, dated as of August 1, 1996 (Enova 1996 Form 10-K Exhibit 10.31).

10.19 Loan agreement with the City of Chula Vista in connection with the issuance of $60 million of Industrial Development Bonds, dated as of November 1, 1996 (Enova 1996 Form 10-K Exhibit 10.32).

10.20 Loan agreement with City of San Diego in connection with the issuance of $57.7 million of Industrial Development Bonds, dated as of June 1, 1995 (June 30, 1995 SDG&E Form 10-Q Exhibit 10.3).

10.21 Loan agreement with the City of San Diego in connection with the issuance of $92.9 million of Industrial Development Bonds 1993 Series C dated as of July 1, 1993 (June 30, 1993 SDG&E Form 10-Q Exhibit 10.2).

10.22 Loan agreement with the City of San Diego in connection with the issuance of $70.8 million of Industrial Development Bonds 1993 Series A dated as of April 1, 1993 (March 31, 1993 SDG&E Form 10-Q Exhibit 10.3).

10.23 Loan agreement with the City of San Diego in connection with the issuance of $118.6 million of Industrial Development Bonds dated as of September 1, 1992 (Sept. 30, 1992 SDG&E Form 10-Q Exhibit 10.1).

10.24 Loan agreement with the City of Chula Vista in connection with the issuance of $250 million of Industrial Development Bonds, dated as of December 1, 1992 (1992 SDG&E Form 10-K Exhibit 10.5).

10.25 Loan agreement with the California Pollution Control Financing Authority in connection with the issuance of $129.82 million of Pollution Control Bonds, dated as of June 1, 1996 (Enova 1996 Form 10-K Exhibit 10.41).

10.26 Loan agreement with the California Pollution Control Financing Authority in connection with the issuance of $60 million of Pollution Control Bonds dated as of June 1, 1993 (June 30, 1993 SDG&E Form 10-Q Exhibit 10.1).

10.27 Loan agreement with the California Pollution Control Financing Authority, dated as of December 1, 1991, in connection with the issuance of $14.4 million of Pollution Control Bonds (1991 SDG&E Form 10-K Exhibit 10.11).

Natural Gas Transportation

Enova Corporation and San Diego Gas & Electric (SDG&E)
- --

10.28 Amendment to Firm Transportation Service Agreement, dated December 2, 1996, between Pacific Gas and Electric Company and San Diego Gas & Electric Company (1997 Enova Corporation Form 10-K Exhibit 10.58).

10.29 Firm Transportation Service Agreement, dated December 31, 1991 between Pacific Gas and Electric Company and San Diego Gas & Electric Company (1991 SDG&E Form 10-K Exhibit 10.7).

10.30 Firm Transportation Service Agreement, dated October 13, 1994 between Pacific Gas Transmission Company and San Diego Gas & Electric Company (1997 Enova Corporation Form 10-K Exhibit 10.60).

Nuclear

Enova Corporation and San Diego Gas & Electric (SDG&E)
- ---

10.31 Uranium enrichment services contract between the U.S. Department of Energy (DOE assigned its rights to the U.S. Enrichment Corporation, a U.S. government-owned corporation, on July 1, 1993) and Southern California Edison Company, as agent for SDG&E and others; Contract DE-SC05-84UEO7541, dated November 5, 1984, effective June 1, 1984, as amended (1991 SDG&E Form 10-K Exhibit 10.9).

10.32 Fuel Lease dated as of September 8, 1983 between SONGS Fuel Company, as Lessor and San Diego Gas & Electric Company, as Lessee, and Amendment No. 1 to Fuel Lease, dated September 14, 1984 and Amendment No. 2 to Fuel Lease, dated March 2, 1987 (1992 SDG&E Form 10-K Exhibit 10.11).

10.33 Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station, approved November 25, 1987 (1992 SDG&E Form 10-K Exhibit 10.7).

10.34 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.33 herein)(1994 SDG&E Form 10-K Exhibit 10.56).

10.35 Second Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.33 herein)(1994 SDG&E Form 10-K Exhibit 10.57).

10.36 Third Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.33 herein)(1996 SDG&E Form 10-K Exhibit 10.59).

10.37 Fourth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.33 herein)(1996 SDG&E Form 10-K Exhibit 10.60).

10.38 Fifth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generation Station (see Exhibit 10.33 herein)(1999 SDG&E Form 10-K Exhibit 10.26).

10.39 Sixth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.33 herein)(1999 SDG&E Form 10-K Exhibit 10.27).

10.40 Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station, approved November 25, 1987 (1992 SDG&E Form 10-K Exhibit 10.8).

10.41 First Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.40 herein)(1996 Form 10-K Exhibit 10.62).

10.42 Second Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.40 herein)(1996 Form 10-K Exhibit 10.63).

10.43 Third Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.40 herein)(1999 SDG&E Form 10-K Exhibit 10.31).

10.44 Fourth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.40 herein)(1999 SDG&E Form 10-K Exhibit 10.32).

10.45 Second Amended San Onofre Agreement among Southern California Edison Company, SDG&E, the City of Anaheim and the City of Riverside, dated February 26, 1987 (1990 SDG&E Form 10-K Exhibit 10.6).

10.46 U. S. Department of Energy contract for disposal of spent nuclear fuel and/or high-level radioactive waste, entered into between the DOE and Southern California Edison Company, as agent for SDG&E and others; Contract DE-CR01-83NE44418, dated June 10, 1983 (1988 SDG&E Form 10-K Exhibit 10N).

Exhibit 12 -- Statement re: Computation Of Ratios

12.01 Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends for the years ended December 31, 2000, 1999, 1998, 1997, and 1996.

Exhibit 13 -- Annual Report to Security Holders

13.01 Sempra Energy 1999 Annual Report to Shareholders. (Such report, except for the portions thereof which are expressly incorporated by reference in this Annual Report, is furnished for the information of the Securities and Exchange Commission and is not to be deemed "filed" as part of this Annual Report).

Exhibit 21 -- Subsidiaries

21.01 Schedule of Significant Subsidiaries at December 31, 2000.

Exhibit 23 -- Independent Auditors' Consent, page 30.

GLOSSARY

AB 1	A California Assembly bill authorizing the California Department of Water Resources to purchase energy for California consumers.
AB 265	California Assembly Bill imposing a 6.5 cent/kWh electric commodity rate ceiling.
AB 1890	California Assembly Bill - California's electric restructuring law.
AB 1421	A California Assembly bill requiring that natural gas utilities provide bundled basic gas service to certain customers.
BCAP	Biennial Cost Allocation Proceeding
Bcf	One Billion Cubic Feet (of natural gas)
CA/AZ	California/Arizona
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DOE	Department of Energy
DGN	Distribuidora de Gas Natural
DTSC	Department of Toxic Substances Control
DWR	California Department of Water Resources
Edison	Southern California Edison Company
EMF	Electric and Magnetic Fields
Energia	Chilquinta Energia S.A.
Enova	Enova Corporation
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GCIM	Gas Cost Incentive Mechanism
Global	Sempra Energy Global Enterprises
Intertie	Pacific Intertie

IOUs	Investor-Owned Utilities
ISO	Independent System Operator
KN	KN Energy, Inc.
kWh	Kilowatt Hour
mmbtu	Million British Thermal Units (of natural gas)
mW	Megawatt
NRC	Nuclear Regulatory Commission
OTC	Over-the-Counter
PBR	Performance-Based Ratemaking/Regulation
PD	Proposed Decision
PE	Pacific Enterprises
PG&E	Pacific Gas and Electric Company
PGE	Portland General Electric Company
PNM	Public Service Company of New Mexico
PRP	Potentially Responsible Party
PSEG	Public Service Enterprise Group
PX	Power Exchange
ROE	Return on Equity
ROR	Rate of Return
SAB	Staff Accounting Bulletin (SEC)
SAG	Sempra Atlantic Gas
SDG&E	San Diego Gas & Electric Company
SEC	Securities and Exchange Commission
SEF	Sempra Energy Financial
SEI	Sempra Energy International
SER	Sempra Energy Resources
SES	Sempra Energy Solutions
SET	Sempra Energy Trading
SoCalGas	Southern California Gas Company

SONGS	San Onofre Nuclear Generating Station
Southwest Powerlink	A transmission line connecting San Diego to Phoenix and intermediate points
UEG	Utility Electric Generation
VaR	Value at Risk
WSPP	Western Systems Power Pool

THE SEMPRA ENERGY
DEFERRED COMPENSATION AND EXCESS SAVINGS PLAN

TABLE OF CONTENTS

THE SEMPRA ENERGY
DEFERRED COMPENSATION AND EXCESS SAVINGS PLAN

Sempra Energy, a California corporation (the "Company"), and its direct and indirect subsidiaries maintain the Sempra Energy Deferred Compensation Plan for Directors, the Sempra Energy Executive Deferred Compensation Plan, the Sempra Energy Deferred Compensation Plan, the Sempra Energy Excess Savings Plan, the Pacific Enterprises Executive Deferred Compensation Plan, the Pacific Enterprises Deferred Compensation Plan for Directors, the Pacific Enterprises Deferred Compensation Plan, the San Diego Gas & Electric Co. deferred compensation agreements and the Enova deferred compensation agreements to provide supplemental retirement income benefits for certain directors and for a select group of management and highly compensated employees.

The Company wishes to merge these plans and agreements in the form of this Sempra Energy Deferred Compensation and Excess Savings Plan (the "Plan") which is designed to provide supplemental retirement income benefits for certain directors and for a select group of management and highly compensated employees through deferrals of salary and incentive compensation and Company matching contributions. This Plan is also designed to provide for benefits that cannot be provided under the Sempra Energy Savings Plan due to the limitations of Code Sections 401(a)(17), 402(g) and 415. This Plan shall be effective as of January 1, 2000.

ARTICLE I.

TITLE AND DEFINITIONS

1.1 Title.

This Plan shall be known as The Sempra Energy Deferred Compensation and Excess Savings Plan.

1.2 Definitions.

Whenever the following words and phrases are used in this Plan, with the first letter capitalized, they shall have the meanings specified below.

(a) "Account" or "Accounts" shall mean a Participant's Deferral Account, 401(k) Excess Account, Company Matching Account and/or Transferred Account.

(b) "Affiliate" has the meaning ascribed to such term in Rule 12b-2 promulgated under the Exchange Act.

(c) "Base Salary" shall mean a Participant's annual base salary, excluding bonus, incentive and all other remuneration for services rendered to the Company, prior to reduction for any salary contributions to a plan established pursuant to Section 125 of the Code or qualified pursuant to Section 401(k) of the Code.

(d) "Beneficial Owner" has the meaning set forth in Rule 1 3d-3 under the Exchange Act.

(e) "Beneficiary" or "Beneficiaries" shall mean the person or persons, including a trustee, personal representative or other fiduciary, last designated in writing by a Participant to receive the benefits specified hereunder in the event of the Participant's death in accordance with Section 9.5.

(f) "Board of Directors" or "Board" shall mean the Board of Directors of the Company.

(g) "Bonus" shall mean the annual incentive award earned by a Participant under the Company's short-term incentive plan. At the Committee's sole discretion, other incentive payments may be included in any Participant's Bonus.

(h) "Change in Control" shall be deemed to have occurred when:

(1) Any Person is or becomes the Beneficial Owner, directly or indirectly, of securities of Sempra Energy representing twenty percent (20%) or more of the combined voting power of Sempra Energy's then outstanding securities; or

(2) The following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including, but not limited to, a consent solicitation, relating to the election of directors of Sempra Energy) whose appointment or election by the Board or nomination for election by Sempra Energy's shareholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors on the date hereof or whose appointment, election or nomination for election was previously so approved or recommended; or

(3) There is consummated a merger or consolidation of Sempra Energy or any direct or indirect subsidiary of Sempra Energy with any other corporation, other than (A) a merger or consolidation which would result in the voting securities of Sempra Energy outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of Sempra Energy or any subsidiary of Sempra Energy, at least sixty percent (60%) of the combined voting power of the securities of Sempra Energy or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (B) a merger or consolidation effected to implement a recapitalization of Sempra Energy (or similar transaction) in which no Person is or becomes the Beneficial Owner, directly or indirectly, of securities of Sempra Energy (not including in the securities beneficially owned by such Person any securities acquired directly from Sempra Energy or its affiliates other than in connection with the acquisition by Sempra Energy or its affiliates of a business) representing twenty percent (20%) or more of the combined voting power of Sempra Energy's then outstanding securities; or

(4) The shareholders of Sempra Energy approve a plan of complete liquidation or dissolution of Sempra Energy or there is consummated an agreement for the sale or disposition by Sempra Energy of all or substantially all of Sempra Energy's assets, other than a sale or disposition by Sempra Energy of all or substantially all of Sempra Energy's assets to an entity, at least sixty percent (60%) of the combined voting power of the voting securities of which are owned by shareholders of Sempra Energy in substantially the same proportions as their ownership of Sempra Energy immediately prior to such sale.

(i) "Code" shall mean the Internal Revenue Code of 1986, as amended.

(j) "Committee" shall mean the compensation committee of the Board of Directors.

(k) "Company" shall mean Sempra Energy and any successor corporations. Company shall also include each corporation which is a member of a controlled group of corporations (within the meaning of Section 414(b) of the Code) of which Sempra Energy is a component member, if the Board provides that such corporation shall participate in the Plan and such corporation's governing board of directors adopts this Plan.

(l) "Company Matching Account" shall mean the bookkeeping account maintained by the Company for each Participant that is credited with an amount equal to the Company Matching Contribution, if any, debited by amounts equal to all distributions to and withdrawals made by the Participant and/or his Beneficiary and adjusted for investment earnings and losses pursuant to Article V. The Company Matching Account may be further subdivided into sub-accounts, one representing the matching contribution, if any, related to any deferral of Compensation, and a second representing the matching contribution, if any, related to any 401(k) Excess contributed to the Plan.

(m) "Company Matching Contributions" shall mean the employer matching contribution made to the Plan on behalf of Participants who make deferrals under Article III.

(n) "Compensation" shall mean Base Salary, Bonus and Dividend Equivalents that the Participant who is an employee is entitled to receive for services rendered to the Company. Compensation shall mean retainer payments and/or meeting and other fees, received from the Company for services performed by any Participant as a Director.

(o) "Deferral Account" shall mean the bookkeeping account maintained by the Company for each Participant that is credited with amounts equal to the portion of the Participant's Compensation that he elects to defer pursuant to Section 3.1, debited by amounts equal to all distributions to and withdrawals made by the Participant and/or his Beneficiary and adjusted for investment earnings and losses pursuant to Article V.

(p) "Deferral Election Form" shall mean the form designated by the Committee for purposes of making deferrals under Section 3.1.

(q) "Director" shall mean an individual who is a non-employee member of the Board.

(r) "Disability" shall mean a "disability" as defined in the Company's long-term disability plan, as then in effect.

(s) "Distributable Amount" shall mean the sum of the vested balance of a Participant's Deferral Account, 401(k) Excess Account, Company Matching Account and Transferred Account.

(t) "Dividend Equivalent" shall mean the phantom dividends relating to post-July 1, 1998 stock option grants under the 1998 Sempra Energy Long-Term Incentive Plan which are eligible for deferral.

(u) "Early Distribution" shall mean an election by a Participant in accordance with Section 7.2 to receive a withdrawal of amounts from his or her Deferral Account, Transferred Account, Company Matching Account and 401(k) Excess Account prior to the time in which such Participant would otherwise be entitled to such amounts.

(v) "Effective Date" shall mean January 1, 2000.

(w) "Election Period" shall mean the period designated by the Committee.

(x) "Eligible Individual" shall mean those individuals selected by the Committee from (i) those employees of the Company who either (A) are Executive Officers or (B) have Base Salary for a Calendar Year that is at least $ 100,000, as adjusted by the Committee from time to time and (ii) those Directors who are not employees of the Company. The Committee may, in its sole discretion, select such other individuals to participate in the Plan who do not otherwise meet the foregoing criteria.

(y) "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended.

(z) "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations thereunder.

(aa) "Executive Officer" shall mean an employee of the Company who holds a position as an executive officer in the Company and is eligible to participate in the Sempra Energy Supplemental Executive Retirement Plan or is so designated by the Committee.

(bb) "401(k) Excess Account" shall mean the bookkeeping account maintained by the Company for each Participant that is credited with amounts equal to the Participant's 401(k) Excess that he elects to defer pursuant to Section 3.1, debited by amounts equal to all distributions to and withdrawals made by the Participant and/or his Beneficiary and adjusted for investment earnings and losses pursuant to Article V.

(cc) "401 (k) Excess" shall mean the amount, if any, which a Participant may not contribute to the applicable 401(k) Plan by reason of Code Section 401(a)(17) or 415 and the regulations issued thereunder, or which may not be contributed to the applicable 401(k) Plan by reason of the limitations set forth in Code Section 402(g).

(dd) "401(k) Plan" shall mean the Sempra Energy Savings Plan maintained by the Company under Code Section 401(k), as in effect from time to time or as applicable for any Participant, a plan maintained by a direct or indirect subsidiary of the Company under Code Section 401(k).

(ee) "Manager" shall mean an employee of the Company who is an Eligible Individual, other than an Executive Officer or a Director.

(ff) "Measurement Fund" shall mean one or more of the investment funds selected by the Committee pursuant to Section 4.2.

(gg) "Moody's Plus Rate" shall mean the Moody's Rate (as defined below) plus the greater of (i) 10% of the Moody's Corporate Bond Yield Average - Monthly Average Corporates as published by Moody's Investors Service, Inc. (or any successor) or (ii) one percentage point per annum. The Moody's Rate for the month of June means the average of the daily Moody's Corporate Bond Yield Average - Monthly Average Corporates for the month of June.

(hh) "Participant" shall mean any Eligible Individual who becomes a Participant in accordance with Article II.

(ii) "Payroll Date" shall mean, with respect to any Participant, the date on which he would otherwise be paid Compensation.

(jj) "Payment Date" shall mean the time as soon as practicable after (1) the first day of the month which is at least 30 days after the date of the Participant's Termination or Retirement, (2) January 1 of the year following the year in which the Participant has a Termination or Retirement, or (3) the Scheduled Withdrawal Date, as the Participant has elected.

(kk) "Person" means any person, entity or "group" within the meaning of Section 13(d)(3) or Section 14(d)(2) of the Exchange Act, except that such term shall not include (i) the Company or any of its Affiliates, (ii) a trustee or other fiduciary holding securities under an employee benefit plan of the Company or any of its Affiliates, (iii) an underwriter temporarily holding securities pursuant to an offering of such securities, (iv) a corporation owned, directly or indirectly, by the shareholders of Sempra Energy in substantially the same proportions as their ownership of stock of Sempra Energy, or (v) a person or group as used in Rule 13d-l(b) under the Exchange Act.

(ll) "Plan" shall mean The Sempra Energy Deferred Compensation and Excess Savings Plan set forth herein, as amended from time to time.

(mm) "Plan Year" shall mean the 12 consecutive month period beginning on each January 1 and ending on each December 31.

(nn) "Prior Plans" shall mean the Sempra Energy Deferred Compensation Plan for Directors, the Sempra Energy Executive Deferred Compensation Plan, the Sempra Energy Deferred Compensation Plan, the Sempra Energy Excess Savings Plan, the Pacific Enterprises Executive Deferred Compensation Plan, the Pacific Enterprises Deferred Compensation Plan for Directors, the Pacific Enterprises Deferred Compensation Plan, the San Diego Gas & Electric Co. deferred compensation agreements and the Enova deferred compensation agreements designed to provide supplemental retirement income benefits for any director or select group of management and highly compensated employees of the Company or its direct and indirect subsidiaries.

(oo) "Prior Rate" shall mean the rate of investment return established under the applicable Prior Plan, subject to the terms of such Prior Plan.

(pp) "Retirement" shall mean, for a Participant who is an employee of the Company, a Participant's voluntary retirement from employment with the Company on or after age 55 and 5 years of employment with the Company in accordance with the Company's retirement policies as then in effect. Retirement shall mean, for a Participant who is a Director, ceasing to be a Director for any reason other than for death or Disability. If a Participant is both an employee of the Company and a Director, Retirement shall occur only after he resigns from both positions.

(qq) "Rule 1 6b-3" shall mean that certain Rule 1 6b-3 under the Exchange Act, as such Rule may be amended from time to time.

(rr) "Scheduled Withdrawal Date" shall be in January in the year elected by the Participant for an in-service withdrawal of all amounts of Compensation or 401(k) Excess deferred in a given Plan Year, but excluding earnings and losses attributable thereto, as set forth on the election forms for such Plan Year.

(ss) "Sempra Energy Stock Fund" shall mean the Measurement Fund in which investment earnings and losses parallel the investment return on the common stock of the Company.

(tt) "Termination" shall mean for any Participant who is an employee, ceasing to be an employee of the Company for reasons other than death, Disability or Retirement. For any Participant who is a Director, "Termination" shall mean ceasing to be a Director for any reason, including death, Disability or Retirement. If a Participant is both an employee of the Company and a Director, he shall not have a Termination until he resigns from both positions.

(uu) "Transferred Account" shall mean the bookkeeping account maintained by the Company for each Participant that is credited with amounts which were transferred from a Prior Plan, debited by amounts equal to all distributions and withdrawals made to the Participant or his Beneficiary and adjusted for investment earnings and losses pursuant to Article V.

(vv) "Valuation Date", with respect to the Measurement Funds that are available under the 401 (k) Plan, shall have the same meaning as under the 401 (k) Plan. For purposes of the Moody's Plus Rate, "Valuation Date" shall mean the last day of the calendar month. For purposes of the Prior Rate, "Valuation Date" shall have the same meaning it has under the applicable Prior Plan.

ARTICLE II.

PARTICIPATION

An Eligible Individual shall become a Participant in the Plan by (1) electing to make deferrals in accordance with Section 3.1 and (2) filing such other forms as the Committee may reasonably require for participation hereunder. Additionally, in order to defer 401(k) Excess, the Eligible Individual must be making 401(k) contributions to the 401(k) Plan at the rate of no less than 6% of compensation (as defined in the 401 (k) Plan) for the year. An Eligible Individual who completes the requirements of the preceding sentences shall commence participation in this Plan as of the first Payroll Date with respect to which Compensation is deferred.

ARTICLE III.

CONTRIBUTIONS

3.1 Elections to Defer Compensation and 401(k) Excess

(a) General Rule. Each Participant may defer Base Salary, Dividend Equivalents, Bonus and/or 401(k) Excess by filing with the Committee a Deferral Election Form that conforms to the requirements of this Section 3.1, no later than the last day of the applicable Election Period. The Committee may permit an Eligible Individual to have his first Election Period during a Plan Year. An election to defer Compensation must be filed during the Election Period prior to the effective date of such election and will be effective for Compensation earned during periods beginning after the effective date of such election.

(b) Deferral Amounts. The amount of Compensation and/or 401 (k) Excess which a Participant may elect to defer is such Compensation and/or 401(k) Excess earned on or after the time at which the Participant elects to defer each Plan Year in accordance with Section 3.1(a). The applicable limitations for any Participant shall be determined based on his classification by the Committee.

(1) Each Participant who is a Manager shall be permitted to defer (A) from 5% to 50% of Base Salary and (B) from 5% to 100% of his Bonus and Dividend Equivalents.

(2) Each Participant who is an Executive Officer shall be permitted to defer (A) from 10% to 100% of Base Salary and (B) from 10% to 100% of his Bonus and Dividend Equivalents.

(3) Each Participant who is a Director shall be permitted to defer from 10% to 100% of his Compensation.

(4) Each Participant who participates in the 401(k) Plan and makes 401(k) contributions at a rate of 6% of compensation (as defined in the 401(k) Plan) per year shall be deemed to make the same election under this Plan that he has made under the applicable 401(k) Plan, not to exceed 15% of Base Salary for purposes of deferring 401(k) Excess under the Plan, unless a contrary election is made under the Plan.

Notwithstanding the limitations established above, the total amount deferred by a Participant may be limited in any calendar year, if necessary, to satisfy the Participant's income and employment tax withholding obligations (including Social Security, unemployment and Medicare), and the Participant's employee benefit plan contribution requirements, as determined in the sole and absolute discretion of the Committee. If permitted by the Committee, the Participant may make deferrals with respect to any designated portion of his Compensation (such as meeting fees, for example).

(c) Ordering Rule. If a Participant elects to defer both Compensation and 401(k) Excess, the Compensation deferrals will be deducted from the Participant's compensation and contributed to the Plan before any 401(k) Excess deferrals.

(d) Duration of Deferral Election.

(1) A Participant's election to defer made during the Election Period immediately preceding the next Plan Year (or, if the Participant's first Election Period, made during a Plan Year) is effective for the next Plan Year (or, if the Participant's first Election Period, for the remainder of the Plan Year), except as modified or suspended.

(2) If permitted by the Administrator, a Participant may modify or suspend his election to defer Compensation and/or 401(k) Excess during a Plan Year only in the event that (A) the Participant has a change in marital status, (B) the Participant has a change in the number of his dependents (as defined under Code Section 152(a)) or (C) the Participant or his spouse has a change in employment status (as determined by the Administrator). Such modification or suspension shall be made by filing such an election during the Election Period immediately prior to the date of such modification or suspension is to be effective.

(3) A Participant's election to defer 401(k) Excess shall automatically be suspended for the remainder of the Plan Year if the Participant's election under the 401 (k) Plan falls below 6% of his compensation (as defined under the 401(k) Plan) per year.

(4) Except as provided in Section 3.1 (b)(4), a Participant must file a new election for each subsequent Plan Year during the Election Period immediately prior to the next Plan Year, which election shall be effective on the first day of the next following Plan Year. In the event a Participant fails to timely file an election for the next Plan Year, he should be deemed to have elected not to have deferred any Compensation and or 401(k) Excess for any relevant period except as provided in Section 3.1(b)(4).

(e) Elections. Subject to the limitations of subsection (b), any Eligible Individual who does not elect to defer Compensation and/or 401(k) Excess during his Election Period may subsequently become a Participant. Subject to the limitations of subsection (b), any Eligible Individual who has terminated a prior deferral election may elect to again defer Compensation and/or 401(k) Excess by filing a Deferral Election Form during a subsequent Election Period.

(f) Termination of Participation and/or Deferrals. If the Committee determines in good faith that a Participant no longer qualifies as a Director or a member of a select group of management or highly compensated employees, as membership in such group is determined in accordance with Sections 201(2), 301(a)(3) and 401(a)(1) of ERISA, the Committee shall have the right, in its sole discretion and only for purposes of preserving the Plan's exemption from Title I of ERISA, to (i) terminate any deferral election the Participant has made for the remainder of the Plan Year in which the Participant's membership status changes, (ii) prevent the Participant from making future deferral elections and/or (iii) immediately distribute the balance of the participant's Accounts and terminate the Participant's participation in the Plan.

3.2 Transfers from Prior Plans.

All amounts credited to this Plan as a result of the merger of the Prior Plans shall be credited to Participants' Transferred Accounts under this Plan. Each Participant is always 100% vested in his Transferred Account at all times. No additional amounts may be contributed to a Participant's Transferred Account other than investment earnings. Any amounts so transferred to a Participant's Transferred Account will be subject to the terms of this Plan for all purposes, except as provided in Section 4.3 and Section 7.1(a)(6).

3.3 Company Matching Contributions

(a) The Company shall make a Company Matching Contribution on behalf of select Participants who make deferrals under Article III in an amount equal to

(1) the product of (A) the rate of the matching contribution under the 401 (k) Plan in which the Participant participates and (B) the sum of the Participant's Base Salary and Bonus,

less

(2) the amount credited to the Participant's matching contribution account under the 401(k) Plan for that Plan Year.

Notwithstanding the above, the Company reserves the right to change the Company Matching Contribution in its sole discretion.

(b) Pursuant to the Committee's procedures, for each Plan Year each Participant's Company Matching Account shall be credited with an amount described in subsection (a) above, if any.

3.4 FICA and Other Taxes.

(a) Annual Deferral Amounts. For each Plan Year in which a Participant who is an employee makes a deferral under Section 3.1, the Company shall withhold from that portion of the Participant's Compensation that is not being deferred, in a manner determined by the Company, the Participant's share of FICA and other employment taxes on such amount. If necessary, the Committee may reduce the Participant's deferrals under Section 3.1 in order to comply with this Section.

(b) Company Matching Amounts. For each Plan Year in which a Participant is credited with a contribution to his or her Company Matching Account under Section 3.3, the Company shall withhold from the Participant's Compensation that is not deferred, in a manner determined by the Company, the Participant's share of FICA and other employment taxes. If necessary, the Committee may reduce the Participant's Company Matching Account in order to comply with this Section.

ARTICLE IV.

INVESTMENTS

4.1 Measurement Funds.

(a) In the manner designated by the Committee, Participants may elect one or more Measurement Funds to be used to determine the additional amounts to be credited to their Accounts. Although the Participant may designate the Measurement Funds, the Committee shall not be bound by such designation. The Committee shall select from time to time, in its sole discretion, the Measurement Funds to be available under the Plan.

(b) No Actual Investment. Notwithstanding any other provision of this Plan that may be interpreted to the contrary, the Measurement Funds are to be used for measurement purposes only, and a Participant's election of any such Measurement Fund, the allocation to his Accounts thereto, the calculation of additional amounts and the crediting or debiting of such amounts to a Participant's Accounts shall not be considered or construed in any manner as an actual investment of his Accounts in any such Measurement Fund. In the event that the Company or the trustee, in its own discretion, decides to invest funds in any or all of the Measurement Funds, no Participant shall have any rights in or to such investments themselves. Without limiting the foregoing, a Participant's Accounts shall at all times be a bookkeeping entry only and shall not represent any investment made on his or her behalf by the Company. The Participant shall at all times remain an unsecured creditor of the Company.

4.2 Investment Elections.

(a) Executive Officers and Director Participants.

(1) Deferral. 401(k) Excess and Transferred Accounts. Except as provided in Section 4.3, Participants who are either Executive Officers or Directors may designate how their Deferral, 401(k) Excess and Transferred Accounts will be deemed to be invested under the Plan.

(A) Such Participants may make separate investment elections for (I) their future deferrals of Compensation and 401(k) Excess as well as transfers under Section 3.2 and (II) the existing balances of their Deferral, 401(k) Excess and Transferred Accounts.

(B) Such Participants may make and change their investment elections by choosing from the Measurement Funds designated by the Committee in accordance with the procedures established by the Committee.

(C) Except as otherwise designated by the Committee, the available Measurement Funds under this Section 4.2(a)(1) shall be the investment funds under the 401(k) Plan (excluding the Stable Value Fund and any brokerage account option).

Additionally, for the Deferral Account only, there shall also be a Measurement Fund based on the Moody's Plus Rate.

(D) If a Participant fails to elect a Measurement Fund under this Section, he shall be deemed to have elected the default Measurement Fund (as designated by the Committee) for all of his Accounts.

(2) Company Matching Account. Participants may not direct the investment of their Company Matching Account which will be deemed to be invested in the Sempra Energy Stock Fund.

(b) Manager Participants.

(1) 401(k) Excess Accounts. Except as provided in Section 4.3, Participants who are Managers may designate how their 401(k) Excess Accounts will be deemed to be invested under the Plan.

(A) Manager Participants may make separate investment elections for (I) their future deferrals of 401 (k) Excess and (II) the existing balances of their 401 (k) Excess Accounts.

(B) Participants may make and change their investment elections by choosing from the Measurement Funds designated by the Committee in accordance with the procedures established by the Committee.

(C) Except as otherwise designated by the Committee, the available Measurement Funds under this Section 4.2(b)(1) for the 401(k) Excess Accounts shall be the investment funds under the 401(k) Plan (excluding the Stable Value Fund and any brokerage account option).

(D) If a Participant fails to elect a Measurement Fund under this Section, he shall be deemed to have elected the default Measurement Fund (as designated by the Committee) for his 401(k) Excess Account.

(2) Deferral Account. Any Participant who is a Manager will have his Deferral Account invested in the Measurement Fund based on the Moody's Plus Rate, except as otherwise permitted by the Committee.

(3) Company Matching Account. Participants may not direct the investment of their Company Matching Account which will be invested in the Sempra Energy Stock Fund.

(c) Participants who have had a Termination but not yet commenced distributions under Article VII or Participants or Beneficiaries who are receiving installment payments may continue to make investment elections pursuant to subsection (a) and (b) above, as applicable, except as otherwise determined by the Committee.

4.3 Investment of Transferred Accounts.

(a) Each Participant's Transferred Account balance shall be treated as invested in a Measurement Fund with a rate of investment return based solely on the Prior Rate, except as provided in subsection (b).

(b) In accordance with the procedures established by the Committee, once each calendar quarter an Executive Officer Participant or a Director Participant may elect to transfer a designated percentage of the balance of his Transferred Account to new Measurement Funds, as provided in Section 4.2. As of the effective date of such an election, such designated percentage of the balance of his Transferred Account may be allocated to the Participant's other Accounts in accordance with the type of contributions with which it is credited (i.e., pre-tax deferrals will be credited to the Participant's Deferral Account). Such portion of the Transferred Account shall cease to be credited with investment returns at the Prior Rate and may not be subsequently invested at the Prior Rate.

4.4 Compliance with Section 16 of the Exchange Act.

(a) Any Participant or Beneficiary who is subject to Section 16 of the Exchange Act shall have his Measurement Fund elections under the Plan subject to the requirements of the Exchange Act, as interpreted by the Committee. Any such Participant or Beneficiary who elects to have any portion of his Deferral, 401 (k) Excess or Transferred Accounts, his future deferrals (pursuant to Section 3.1) or future transfers (pursuant to Section 3.2) either (i) invested in the Sempra Energy Stock Fund or (ii) transferred from the Sempra Energy Stock Fund to another available Measurement Fund under the Plan may not make an election with the opposite effect under this Plan or any other Company-sponsored plan until six months and one day following the original election.

(b) Notwithstanding any other provision of the Plan or any rule, instruction, election form or other form, the Plan and any such rule, instruction or form shall be subject to any additional conditions or limitations set forth in any applicable exemptive rule under Section 16 of the Exchange Act (including any amendment to Rule 1 6b-3) that are requirements for the application of such exemptive rule. To the extent permitted by applicable law, such Plan provision, rule, instruction or form shall be deemed amended to the extent necessary to conform to such applicable exemptive rule.

ARTICLE V.

ACCOUNTS

5.1 Accounts.

(a) The Committee shall establish and maintain a Deferral Account, 401 (k) Excess Account, Transferred Account and Company Matching Account for each Participant under the Plan. Each Participant's Accounts shall be further divided into separate subaccounts ("investment fund subaccounts"), each of which corresponds to a Measurement Fund elected by the Participant pursuant to Section 4.2.

(b) The performance of each elected Measurement Fund (either positive or negative) will be determined by the Committee, in its reasonable discretion, based on the performance of the Measurement Funds themselves. A Participant's Accounts shall be credited or debited on each Valuation Date based on the performance of each Measurement Fund selected by the Participant, as determined by the Committee in its sole discretion, as though (i) a Participant's Accounts were invested in the Measurement Fund(s) selected by the Participant, in the percentages applicable to such period, as of the close of business on the first business day of such period, at the closing price on such date; (ii) the portion of the Participant's Compensation that was actually deferred pursuant to Section 3.1 during any period were invested in the Measurement Fund(s) selected by the Participant, in the percentages applicable to such period, no later than the close of business on the first business day after the day on which such amounts are actually deferred from the Participant's Compensation, at the closing price on such date; and (iii) any withdrawal or distribution made to a Participant that decreases such Participant's Accounts ceased being invested in the Measurement Fund(s), in the percentages applicable to such period, no earlier than one business day prior to the distribution, at the closing price on such date. The Participant's Company Matching Contribution, if any, shall be credited to his Company Matching Account for purposes of this Section in the manner determined by the Committee.

ARTICLE VI.

VESTING

Each Participant shall be 100% vested in his Deferral Account, 401(k) Excess Account, Matching Account and Transferred Account at all times.

ARTICLE VII.

DISTRIBUTIONS

7.1 Distribution of Accounts.

(a) Distribution at Termination. Disability or Retirement.

(1) Normal Form. Except as provided in subsection 7.1(a)(2), subsection 7.1 (a)(6) or Section 7.4, upon the Termination, Disability or Retirement of the Participant, the Distributable Amount shall be paid to the Participant in substantially equal annual installments over 10 years beginning on the Participant's Payment Date.

(2) Optional Forms. Instead of receiving his Distributable Amount as described at Section 7.1(a)(1), the Participant may elect one of the following optional forms of payment (on the form provided by Company) at the time of his deferral election:

(i) annual installments (calculated as set forth at subsection 7.1 (a)(5)) over 5 years beginning on the Participant's Payment Date,

(ii) annual installments (calculated as set forth at subsection 7. l(a)(5)) over 15 years beginning on the Participant's Payment Date, or

(iii) a lump sum.

A Participant may change his election with respect to the frequency of payment, provided such change in the frequency of payment occurs at least one year prior to the Participant's Termination or Retirement.

(3) Small Accounts. Notwithstanding any provision to the contrary, in the event the Distributable Amount is equal to or less than $25,000, such Distributable Amount shall be distributed to the Participant (or his Beneficiary, as applicable) in a lump sum.

(4) Investment Adjustments. The Participant's Accounts shall continue to be adjusted for investment earnings and losses pursuant to Section 4.2 and Section 4.3 of the Plan until all amounts credited to his Accounts under the Plan have been distributed.

(5) Calculating Installments. All installment payments made under the Plan shall be determined in accordance with the annual fractional payment method, calculated as follows: the balance of the Participant's Accounts shall be calculated as of the close of business on the last business day of the year. The annual installment shall be calculated by multiplying this balance by a fraction, the numerator of which is one, and the denominator of which is the remaining number of annual payments due the Participant. By way of example, if the Participant elects 10 year installments the first payment shall be 1/10 of the balance of his Accounts calculated as described in this definition. The following year, the payment shall be 1/9 of the balance of the Participant's Accounts, calculated as described in this definition. Each annual installment shall be paid on or as soon as practicable after the last business day of the applicable year.

(6) Distribution of Transferred Accounts. Until a Participant so elects, his Transferred Account shall be subject to his most recent form of distribution election in effect under the applicable Prior Plan. However, if the Participant elects to apply his distribution election in effect under this Plan to the balance of his Transferred Account, then any prior distribution election under the Prior Plan shall automatically be permanently revoked.

(b) Distribution on a Scheduled Withdrawal Date.

(i) In the case of a Participant who has elected a Scheduled Withdrawal Date for a distribution while still in the employ of the Company or while still a Director, such Participant shall receive his or her deferrals of Compensation and 401 (k) Excess (but excluding any investment earnings on such amounts) (the "Withdrawal Amount") as shall have been elected by the Participant to be subject to the Scheduled Withdrawal Date. A Participant's Scheduled Withdrawal Date with respect to amounts of Compensation and/or 401(k) Excess deferred in a given Plan Year be at least three years from the last day of the Plan Year for which such deferrals are made.

(ii) The Withdrawal Amount shall be paid in a lump sum.

(iii) A Participant may extend the Scheduled Withdrawal Date for the Withdrawal Amount for any Plan Year, provided such extension occurs at least one year before the scheduled Withdrawal Date and is for a period of not less than five years from the Scheduled

Withdrawal Date. The Participant shall have the right to modify any Scheduled Withdrawal Date only once, without the consent of the Committee, by submitting a written notice of such modification to the Committee at least one year in advance of the originally elected Scheduled Withdrawal Date. A Participant who has modified a Scheduled Withdrawal Date, may again once further modify the Scheduled Withdrawal Date, but only with the consent of the Committee.

(iv) In the event of Participant's Termination, Disability or Retirement prior to a Scheduled Withdrawal Date, the Participant's entire Withdrawal Amount will be paid in accordance with the Participant's election under Section 7.1(b). In the event of a Participant's death prior to a Scheduled Withdrawal Date, the Participant's entire Withdrawal Amount will be paid as soon as practicable after the Termination in a lump sum.

(c) Distribution upon Death. In the event a Participant dies before he has begun receiving distributions under Section 7.1(a), his Accounts will be paid to his Beneficiary in the same manner elected by the Participant. In the event a Participant dies after he has begun receiving distributions under Section 7.1 (a) with a remaining balance in his Accounts, the balance shall continue to be paid to his Beneficiary in the same manner. Notwithstanding the above, the Committee may, in its sole discretion, permit the Beneficiary to receive an immediate lump sum payment of the Participant's Accounts reduced by a penalty of 10% of the balance of the Accounts. The penalty amount shall be permanently forfeited and the Company shall have no obligation to the Beneficiary with respect to such forfeited amount.

(d) Other Distribution. Independent of any termination of this Plan, if the Internal Revenue Service makes a final determination that amounts under this Plan are immediately taxable to any Participant or Beneficiary, the Committee has the discretion to accelerate distributions under the Plan to such Participants or Beneficiaries.

7.2 Early Distributions.

A Participant shall be permitted to elect an Early Distribution from his or her Deferral Account, 401(k) Excess Account and Transferred Account prior to the Payment Date, subject to the following restrictions:

(a) The election to take an Early Distribution shall be made by filing a form provided by and filed with the Committee prior to the end of any calendar month.

(b) The amount of the Early Distribution shall in all cases be an amount not less than $10,000.

(c) The amount described in subsection (b) above shall be paid in a single cash lump sum as soon as practicable after the end of the calendar month in which the Early Distribution election is made.

(d) If a Participant requests an Early Distribution, 10% of the gross amount to be distributed shall be permanently forfeited and the Company shall have no obligation to the Participant or his Beneficiary with respect to such forfeited amount.

(e) If a Participant receives an Early Distribution the Participant will be ineligible to contribute deferrals to the Plan for the remainder of the Plan Year and for the next following Plan Year.

7.3 Hardship Distribution.

(a) A Participant shall be permitted to elect a Hardship Distribution of all or a portion of his Accounts under the Plan prior to the Payment Date, subject to the following restrictions:

(1) The election to take a Hardship Distribution shall be made by filing the form provided by the Committee before the date established by the Committee.

(2) The Committee shall have made a determination in its sole discretion that the requested distribution constitutes a Hardship Distribution in accordance with subsection (b).

(3) The amount determined by the Committee as a Hardship Distribution shall be paid in a single cash lump sum as soon as practicable after the end of the calendar month in which the Hardship Distribution election is made and approved by the Committee.

(4) If a Participant receives a Hardship Distribution, the Participant will be ineligible to contribute deferrals to the Plan for the balance of the Plan Year and the following Plan Year.

(b) "Hardship Distribution" shall mean a severe financial hardship to the Participant resulting from (i) a sudden and unexpected illness or accident of the Participant or of his or her dependent (as defined in Section 1 52(a) of the Code), (ii) loss of a Participant's property due to casualty, or (iii) other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. The circumstances that would constitute an unforeseeable emergency will depend upon the facts of each case, but, in any case, a Hardship Distribution may not be made to the extent that such hardship is or may be relieved (A) through reimbursement or compensation by insurance or otherwise, (B) by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship or (C) by cessation of deferrals under this Plan

7.4 Effect of a Chance in Control.

(a) In the event there is a Change in Control, the person who is the chief executive officer (or, if not so identified, the Company's highest ranking officer) shall name a third-party fiduciary as the sole member of the Committee immediately prior to such Change in Control. The appointed fiduciary, in its sole discretion, may permit immediate distributions. If permitted by the appointed fiduciary, a Participant who has a Termination within 24 months of the effective date of the Change in Control may elect one of the optional forms of distribution as provided in Section 7.1(a)(2).l

(b) Upon and after the occurrence of a Change in Control, the Company must (i) pay all reasonable administrative fees and expenses of the appointed fiduciary and (ii) indemnify the appointed fiduciary against any costs, expenses and liabilities including, without limitation, attorney's fees and expenses arising in connection with the appointed fiduciary's duties hereunder, other than with respect to matters resulting from the gross negligence of the appointed fiduciary or its agents or employees and (iii) timely provide the appointed fiduciary with all necessary information related to the Plan, the Participants and Beneficiaries.

(c) Notwithstanding Section 9.4, in the event there is a Change in Control no amendment may be made to this Plan except as approved by the third-party fiduciary. Upon a Change in Control, assets shall be placed in a rabbi trust in an amount which shall equal the full accrued liability under this Plan as determined by Towers Perrin, or a successor actuarial firm.

7.5 Inability to Locate Participant.

In the event that the Committee is unable to locate a Participant or Beneficiary within two years following the required Payment Date, the amount allocated to the Participant's Accounts shall be forfeited. If, after such forfeiture, the Participant or Beneficiary later claims such benefit, such benefit shall be reinstated without interest or earnings from the date of forfeiture, subject to applicable escheat laws.

ARTICLE VIII.

ADMINISTRATION

8. I Committee.

The Committee shall administer the Plan in accordance with this Article.

8.2 Administrator.

The Committee may designate an individual (who need not be a member of the Committee) to handle the day-to-day Plan administration (the "Administrator"). If the Committee does not make such a designation, the Administrator shall be the Senior Vice-President of Human Resources. The Administrator, unless restricted by the Committee, shall exercise the powers under Sections 8.4 and 8.5 except when the exercise of such authority would materially affect the cost of the Plan to the Company or materially increase benefits to Participants.

8.3 Committee Action.

The Committee shall act at meetings by affirmative vote of a majority of the members of the Committee. Any action permitted to be taken at a meeting may be taken without a meeting if, prior to such action, a written consent to the action is signed by all members of the Committee and such written consent is filed with the minutes of the proceedings of the Committee. A member of the Committee shall not vote or act upon any matter which relates solely to himself or herself as a Participant. The chairman or any other member or members of the Committee designated by the chairman may execute any certificate or other written direction of behalf of the Committee.

8.4 Powers and Duties of the Committee.

(a) The Committee, on behalf of the Participants and their Beneficiaries, shall enforce the Plan in accordance with its terms, shall be charged with the general administration of the Plan, and shall have all powers necessary to accomplish its purposes as set forth herein, including, but not by way of limitation, the following:

(1) To select the Measurement Funds in accordance with Section 4.2 hereof;

(2) To construe and interpret the terms and provisions of the Plan and to remedy any inconsistencies or ambiguities hereunder;

(3) To select employees eligible to participate in the Plan;

(4) To compute and certify to the amount and kind of benefits payable to Participants and their Beneficiaries;

(5) To maintain all records that may be necessary for the administration of the Plan;

(6) To provide for the disclosure of all information and the filing or provision of all reports and statements to Participants, Beneficiaries or governmental agencies as shall be required by law;

(7) To make and publish such rules for the regulation of the Plan and procedures for the administration of the Plan as are not inconsistent with the terms hereof;

(8) To appoint a plan administrator or any other agent, and to delegate to them such powers and duties in connection with the administration of the Plan as the Committee may from time to time prescribe; and

(9) To take all actions necessary for the administration of the Plan.

8.5 Construction and Interpretation.

The Committee shall have full discretion to construe and interpret the terms and provisions of this Plan, which interpretations or construction shall be final and binding on all parties, including but not limited to the Company and any Participant or Beneficiary. The Committee shall administer such terms and provisions in a uniform and nondiscriminatory manner and in full accordance with any and all laws applicable to the Plan.

8.6 Information.

To enable the Committee to perform its functions, the Company shall supply full and timely information to the Committee on all matters relating to the Compensation of all Participants, their death or other events which cause termination of their participation in this Plan, and such other pertinent facts as the Committee may require.

8.7 Compensation, Expenses, and Indemnity.

(a) The members of the Committee shall serve without compensation for their services hereunder.

(b) The Committee is authorized at the expense of the Company to employ such legal counsel and other advisors as it may deem advisable to assist in the performance of its duties hereunder. Expenses and fees in connection with the administration of the Plan shall be paid by the Company.

(c) To the extent permitted by applicable state law, the Company shall indemnify and save harmless the Committee and each member thereof, the Board of Directors and any delegate of the Committee who is an employee of the Company against any and all expenses, liabilities and claims, including legal fees to defend against such liabilities and claims arising out of their discharge in good faith of responsibilities under or incident to the Plan, other than expenses and liabilities arising out of willful misconduct. This indemnity shall not preclude such further indemnities as may be available under insurance purchased by the Company or provided by the Company under any bylaw, agreement or otherwise, as such indemnities are permitted under state law.

8.8 Quarterly Statements.

Under procedures established by the Committee, a Participant shall receive a statement with respect to such Participant's Accounts on a quarterly basis as of each March 31, June 30, September 30 and December 31.

8.9 Disputes.

(a) Claim.

A person who believes that he or she is being denied a benefit to which he or she is entitled under this Agreement (hereinafter referred to as "Claimant") may file a written request for such benefit with the Administrator, setting forth his or her claim. The request must be addressed to the Administrator at the Company at its then principal place of business.

(b) Claim Decision.

Upon receipt of a claim, the Administrator shall advise the Claimant that a reply will be forthcoming within 90 days and shall, in fact, deliver such reply within such period. The Administrator may, however, extend the reply period for an additional 90 days for special circumstances.

If the claim is denied in whole or in part, the Administrator shall inform the Claimant in writing, using language calculated to be understood by the Claimant, setting forth: (i) the specified reason or reasons for such denial; (ii) the specific reference to pertinent provisions of this Agreement on which such denial is based; (iii) a description of any additional material or information necessary for the Claimant to perfect his or her claim and an explanation of why such material or such information is necessary; (iv) appropriate information as to the steps to be taken if the Claimant wishes to submit the claim for review; and (v) the time limits for requesting a review under subsection (c).

(c) Request For Review.

With 60 days after the receipt by the Claimant of the written opinion described above, the Claimant may request in writing a review the determination of the Administrator. Such review shall be completed by the Senior Vice-President of Human Resources of the Company for Participants who are Managers and by the Committee for Participants who are Executive Officers or Directors. Such request must be addressed to the Secretary of the Company, at its then principal place of business. The Claimant or his or her duly authorized representative may, but need not, review the pertinent documents and submit issues and comments in writing for consideration by the Senior Vice-President of Human Resources or the Committee, as applicable. If the Claimant does not request a review within such 60 day period, he or she shall be barred and estopped from challenging the Administrator's determination.

(d) Review of Decision.

Within 60 days after the receipt of a request for review by the Senior Vice-President of Human Resources or the Compensation Committee, as applicable, after considering all materials presented by the Claimant, the Senior Vice-President of Human Resources or the Compensation Committee, as applicable, will inform the Participant in writing, in a manner calculated to be understood by the Claimant, the decision setting forth the specific reasons for the decision contained specific references to the pertinent provisions of this Plan on which the decision is based. If special circumstances require that the 60 day time period be extended, the Senior Vice- President of Human Resources or the Compensation Committee, as applicable, will so notify the Claimant and will render the decision as soon as possible, but no later than 120 days after receipt of the request for review.

ARTICLE IX.

MISCELLANEOUS

9.1 Unsecured General Creditor.

Participants and their Beneficiaries, heirs, successors, and assigns shall have no legal or equitable rights, claims, or interest in any specific property or assets of the Company. No assets of the Company shall be held in any way as collateral security for the fulfilling of the obligations of the Company under this Plan. Any and all of the Company's assets shall be, and remain, the general unpledged, unrestricted assets of the Company. The Company's obligation under the Plan shall be merely that of an unfunded and unsecured promise of the Company to pay money in the future, and the rights of the Participants and Beneficiaries shall be no greater than those of unsecured general creditors. It is the intention of the Company that this Plan be unfunded for purposes of the Code and Title I of ERISA.

9.2 Restriction Against Assignment.

(a) The Company shall pay all amounts payable hereunder only to the person or persons designated by the Plan and not to any other person or entity. No right, title or interest in the Plan or in any account may be sold, pledged, assigned or transferred in any manner other than by will or the laws of descent and distribution. No right, title or interest in the Plan or in any Account shall be liable for the debts, contracts or engagements of the Participant or his successors in interest or shall be subject to disposition by transfer, alienation, anticipation, pledge, encumbrance, assignment or any other means whether such disposition be voluntary or involuntary or by operation of law by judgment, levy, attachment, garnishment or any other legal or equitable proceedings (including bankruptcy), and any attempted disposition thereof shall be null and void and of no effect, except to the extent that such disposition is permitted by the preceding sentence.

(b) Notwithstanding the provisions of subsection (a), a Participant's interest in his Account may be transferred by the Participant pursuant to a domestic relations order that constitutes a "qualified domestic relations order" as defined by the Code or Title I of ERISA.

9.3 Withholding.

There shall be deducted from each payment made under the Plan or any other Compensation payable to the Participant (or Beneficiary) all taxes which are required to be withheld by the Company in respect to such payment or this Plan. The Company shall have the right to reduce any payment (or compensation) by the amount of such of cash sufficient to provide the amount of said taxes.

9.4 Amendment, Modification, Suspension or Termination.

Subject to Section 7.4, the Committee may amend, modify, suspend or terminate the Plan in whole or in part, except that no amendment, modification, suspension or termination shall have any retroactive effect to reduce any vested amounts allocated to a Participant's Accounts. In the event of Plan termination, distributions may be accelerated.

9.5 Designation of Beneficiary.

(a) Each Participant shall have the right to designate, revoke and redesignate Beneficiaries hereunder and to direct payment of his Distributable Amount to such Beneficiaries upon his death.

(b) Designation, revocation and redesignation of Beneficiaries must be made in writing in accordance with the procedures established by the Committee and shall be effective upon delivery to the Committee.

(c) No designation of a Beneficiary other than the Participant's spouse shall be valid unless consented in writing by such spouse. If there is no Beneficiary designation in effect, or the designated beneficiary does not survive the Participant, then the Participant's spouse shall be the Beneficiary. If there is no surviving spouse, the duly appointed and currently acting personal representative of the Participant's estate (which shall include either the Participant's probate estate or living trust) shall be the Beneficiary.

(d) After the Participant's death, any Beneficiary (other than the Participant's estate) who is to receive installment payments may designate a secondary beneficiary to receive amounts due under this Plan to the Beneficiary in the event of the Beneficiary's death prior to receiving full payment from the Plan. If no secondary beneficiary is designated, it shall be the Beneficiary's estate.

9.6 Insurance.

(a) As a condition of participation in this Plan, each Participant shall, if requested by the Committee or the Company, undergo such examination and provide such information as may be required by the Company with respect to any insurance contracts on the Participant's life and shall authorize the Company to purchase life insurance on his life, payable to the Company.

(b) If an insurance policy is invalidated because a Participant commits suicide during the two-year period beginning on the first day of the first Plan Year of such Participant's participation in the Plan, or if the Participant makes any material misstatement of information or nondisclosure of medical history, then no benefits will be payable hereunder to such Participant, his Beneficiary or his surviving spouse, other than payment of the amount of deferrals of Compensation and/or 401(k) Excess then credited to the Participant's Accounts, without any interest including interest theretofore credited under this Plan.

9.7 Governing Law.

Subject to ERISA, this Plan shall be construed, governed and administered in accordance with the laws of the State of California.

9.8 Receipt of Release.

Any payment to a Participant or the Participant's Beneficiary in accordance with the provisions of the Plan shall, to the extent thereof, be in full satisfaction of all claims against the Committee and the Company. The Committee may require such Participant or Beneficiary, as a condition precedent to such payment, to execute a receipt and release to such effect.

9.9 Compliance with Code Section 162(m)

It is the intent of the Company that any Compensation which is deferred under the Plan by a person who is, with respect to the year of distribution, deemed by the Committee to be a "covered employee" within the meaning of Code Section 162(m) and regulations thereunder, which Compensation constitutes either "qualified performance-based compensation" within the meaning of Code Section 1 62(m) and regulations thereunder or compensation not otherwise subject to the limitation on deductibility under Section 162(m) and regulations thereunder, shall not, as a result of deferral hereunder, become compensation with respect to which the Company in fact would not be entitled to a tax deduction under Code Section 162(m). If the Company determines in good faith prior to a Change in Control that there is a reasonable likelihood that any compensation paid to a Participant for a taxable year of the Company would not be deductible by the Company solely by reason of the limitation under Code Section 1 62(m), then to the extent deemed necessary by the Company to ensure that the entire amount of any distribution to the Participant pursuant to this Plan prior to the Change in Control is deductible, the Company may defer all or any portion of a distribution under this Plan. Any amounts deferred pursuant to this limitation shall continue to be credited/debited with additional amounts in accordance with Article IV, even if such amount is being paid out in installments. The amounts so deferred and amounts credited thereon shall be distributed to the Participant or his Beneficiary (in the event of the Participant's death) at the earliest possible date, as determined by the Company in good faith, on which the deductibility of compensation paid or payable to the Participant for the taxable year of the Company during which the distribution is made will not be limited by Section 1 62(m), or if earlier, the effective date of a Change in Control. Notwithstanding anything to the contrary in this Plan, this Section shall not apply to any distributions made after a Change in Control.

9.10 Payments on Behalf of Persons Under Incapacity.

In the event that any amount becomes payable under the Plan to a person who, in the sole judgment of the Committee, is considered by reason of physical or mental condition to be unable to give a valid receipt therefore, the Committee may direct that such payment be made to any person found by the Committee, in its sole judgment, to have assumed the care of such person. Any payment made pursuant to such termination shall constitute a full release and discharge of the Committee and the Company.

9.11 Limitation of Rights

Neither the establishment of the Plan nor any modification thereof, nor the creating of any fund or account, nor the payment of any benefits shall be construed as giving to any Participant or other person any legal or equitable right against the Company except as provided in the Plan. In no event shall the terms of employment of, or membership on the Board by, any Participant be modified or in any be effected by the provisions of the Plan.

9.12 Exempt ERISA Plan

The Plan is intended to be an unfunded plan maintained primarily to provide deferred compensation benefits for directors and a select group of management or highly compensated employees within the meaning of Sections 201, 301 and 401 of ERISA and therefore to be exempt from Parts 2, 3 and 4 of Title I of ERISA.

9.13 Notice

Any notice or filing required or permitted to be given to the Committee under the Plan shall be sufficient if in writing and hand delivered, or sent by registered or certified mail, to the principal office of the Company, directed to the attention of the General Counsel and Secretary of the Company. Such notice shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification.

9.14 Errors and Misstatements

In the event of any misstatement or omission of fact by a Participant to the Committee or any clerical error resulting in payment of benefits in an incorrect amount, the Committee shall promptly cause the amount of future payments to be corrected upon discovery of the facts and shall pay or, if applicable, cause the Plan to pay, the Participant or any other person entitled to payment under the Plan any underpayment in a lump sum or to recoup any overpayment from future payments to the Participant or any other person entitled to payment under the Plan in such amounts as the Committee shall direct or to proceed against the Participant or any other person entitled to payment under the Plan for recovery of any such overpayment

9.15 Pronouns and Plurality.

The masculine pronoun shall include the feminine pronoun, and the singular the plural where the context so indicates.

9.16 Severability.

In the event that any provision of the Plan shall be declared unenforceable or invalid for any reason, such unenforceability or invalidity shall not affect the remaining provisions of the Plan but shall be fully severable, and the Plan shall be construed and enforced as if such unenforceable or invalid provision had never been included herein.

9.17 Status

The establishment and maintenance of, or allocations and credits to, the Accounts of any Participant shall not vest in any Participant any right, title or interest in and to any Plan assets or benefits except at the time or times and upon the terms and conditions and to the extent expressly set forth in the Plan.

9.18 Headings.

Headings and subheadings in this Plan are inserted for convenience of reference only and are not to be considered in the construction of the provisions hereof.

EXHIBIT 12.1

SEMPRA ENERGY
COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES
AND PREFERRED STOCK DIVIDENDS
(Dollars in millions)

	1996	1997	1998	1999	2000
Fixed Charges and Preferred Stock Dividends:					
Interest	$ 205	$ 209	$ 210	$ 233	305
Interest Portion of Annual Rentals	28	25	20	10	8
Preferred dividends of subsidiaries (1)	37	31	18	16	18
Total Fixed Charges and Preferred Stock Dividends For Purpose of Ratio	$ 270	$ 265	$ 248	$ 259	$ 331
Earnings:					
Pretax income from continuing operations	$ 727	$ 733	$ 432	$ 573	$ 699
Add:					
Fixed charges (from above)	270	265	248	259	331
Less:					
Fixed charges capitalized	5	3	3	5	5
Equity income of unconsolidated subsidiaries and joint ventures	-	-	-	-	62
Total Earnings for Purpose of Ratio	$ 992	$ 995	$ 677	$ 827	$ 963
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.67	3.75	2.73	3.19	2.91

(1) In computing this ratio, "Preferred dividends of subsidiaries" represents the before-tax earnings necessary to pay such dividends, computed at the effective tax rates for the applicable periods.

EXHIBIT 13.01

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

INTRODUCTION

This section includes management's discussion and analysis of operating results from 1998 through 2000, and provides information about the capital resources, liquidity and financial performance of Sempra Energy and its subsidiaries (together referred to as "the company"). This section also focuses on the major factors expected to influence future operating results and discusses investment and financing plans. It should be read in conjunction with the consolidated financial statements included in this Annual Report.

The company is a California-based Fortune 500 energy services company whose principal subsidiaries are San Diego Gas & Electric (SDG&E), which provides electric and natural gas service in San Diego County and southern Orange County, and Southern California Gas Company (SoCalGas), the nation's largest natural gas distribution utility, serving 5 million meters throughout most of Southern California and part of central California. Together, the two utilities serve approximately 7 million meters. In addition, Sempra Energy owns and operates other regulated and unregulated subsidiaries. Sempra Energy Trading (SET) is engaged in the wholesale trading and marketing of natural gas, power and petroleum. Sempra Energy International (SEI) develops, operates and invests in energy-infrastructure systems and power-generation facilities outside the United States. Sempra Energy Resources (SER) develops power plants and natural gas storage, production and transportation facilities within the United States. Sempra Energy Financial (SEF) invests in limited partnerships, which own 1,300 affordable-housing properties throughout the United States. Through other subsidiaries, the company owns and operates centralized heating and cooling for large building complexes, and is involved in domestic energy-utility operations and other energy-related products and services.

The uncertainties shaping California's electric industry and business environment significantly affect the company's operations. A flawed electric-industry restructuring plan, electricity supply/demand imbalances, and legislative and regulatory responses, including a temporary rate ceiling on the cost of electricity that SDG&E can pass on to its small-usage customers on a current basis, have materially and adversely affected the timing of revenue collections by SDG&E and related cash flows. These, together with concerns with California utility regulation generally and increased electricity cost undercollections, have significantly impaired the company's access to the capital markets and ability to obtain financing on commercially reasonable terms. In addition, supply/demand imbalances are affecting the price of natural gas in California more than in the rest of the country because of California's dependence on natural gas fired electric generation due to air-quality considerations. These recent developments are continuing to change rapidly. Information as of March 7, 2001, the date this report was prepared, is found herein, primarily under "California Utility Operations" and "Factors Influencing Future Performance" and in Note 14 of the notes to Consolidated Financial Statements.

BUSINESS-COMBINATION COSTS

Sempra Energy was formed to serve as a holding company for Pacific Enterprises (PE), the parent corporation of SoCalGas, and Enova Corporation (Enova), the parent corporation of SDG&E, in connection with a business combination that became effective on June 26, 1998 (the PE/Enova business combination). In connection with the PE/Enova business combination, the holders of common stock of PE and Enova became the holders of the company's common stock. The preferred stock of PE remained outstanding. The combination was a tax-free transaction. Expenses incurred in connection with the PE/Enova business combination were $70 million, aftertax, for the year ended December 31, 1998. No significant expenses were incurred subsequently.

On February 22, 1999, the company and KN Energy, Inc. (KN) announced that their respective boards of directors had approved the company's acquisition of KN. On June 21, 1999, the company terminated its agreement to acquire KN. Expenses incurred in connection with the KN transaction were $11 million, aftertax, all in the year ended December 31, 1999.

In January 1998, PE and Enova jointly acquired CES/Way International, Inc. (CES/Way), which was subsequently renamed Sempra Energy Services. Expenses incurred in connection with the CES/Way acquisition were $15 million, aftertax, all in the year ended December 31, 1998.

The costs of the transactions discussed above and similar, smaller transactions consist primarily of employee-related costs, and investment banking, legal, regulatory and consulting fees. See Note 1 of the notes to Consolidated Financial Statements for additional information.

CAPITAL RESOURCES AND LIQUIDITY

The company's California utility operations have historically been a major source of liquidity. However, higher electric-commodity prices and the inability of SDG&E to bill its small-usage customers on a current basis for the full purchase cost of electricity due to legislative actions, have resulted in a significant decrease in cash flow available from SDG&E's operating activities in 2000. SDG&E had incurred costs in excess of amounts which it can bill its customers on a current basis, or "undercollected costs," of $447 million at December 31, 2000, and $605 million at January 31, 2001. California recently enacted legislation authorizing the California Department of Water Resources (DWR) to purchase electricity for resale to all California investor-owned utility retail end-use customers (including customers of SDG&E), that is intended to halt or substantially slow the growth of cost undercollections by SDG&E and other California Investor-Owned Utilities (IOUs). Consequently, SDG&E believes that its continued accumulation of undercollected costs will depend primarily upon the effects of this legislation and other legislative and regulatory developments. For additional discussion, see "California Utility Operations" herein and Note 14 of the notes to Consolidated Financial Statements.

Additional working capital and other requirements for the California utilities are met primarily through the issuance of long-term debt. Cash requirements at the utilities primarily consist of capital expenditures for utility plant. The company's nonutility cash requirements include additional investments in SET, SEI, SER and other ventures. These requirements are met through the issuance of short-term and long-term debt by the company or its subsidiaries, as well as from cash flow generated from growing nonutility operations. Due to the factors described herein and in Note 14 of the notes to Consolidated Financial Statements regarding high electricity costs, and the company's inability to bill its small-usage customers on a current basis for the full cost of electricity purchases, management is unable to determine whether the sources of funding described above are sufficient to provide for all of the capital expenditures it otherwise would intend to make, after funding its basic liquidity needs, as described below.

Continued purchases by the DWR for resale to SDG&E's customers of substantially all of the electricity that would otherwise be purchased by SDG&E (as further discussed under "California Utility Operations" herein) or dramatic decreases in wholesale electricity prices, favorable action by the CPUC on SDG&E's electric rate surcharge application discussed below and SDG&E's access to the capital markets are required to manage and finance SDG&E's cost undercollections and provide adequate liquidity.

Other company subsidiaries have significant receivables from the other IOUs and from the California Power Exchange (PX) and the Independent System Operator (ISO), which are described under "California Utility Operations." The collection of these receivables may depend on satisfactory resolution of the financial difficulties being experienced by those IOUs as a result of the California electric industry problem discussed above. In addition, the company's ability to fund its subsidiaries' capital expenditure program and liquidity requirements is significantly affected by the company's credit ratings and related ability to obtain financing on commercially reasonable terms.

CASH FLOWS FROM OPERATING ACTIVITIES

The decrease in cash flows from operating activities in 2000 was primarily due to increased net trading assets, SDG&E's refunds to customers for surplus rate-reduction-bond proceeds, SDG&E's cost undercollections related to high electric-commodity prices and energy charges in excess of the 6.5 cents/kWh ceiling in accordance with AB 265 (see "California Utility Operations" below and Note 14 of the notes to Consolidated Financial Statements) and increased accounts receivable. These factors were partially offset by higher overcollected regulatory balancing accounts at SoCalGas, increased accounts payable and lower income tax payments. The increases in accounts receivable and accounts payable were primarily due to higher sales volumes and higher prices for natural gas and purchased power.

The decrease in cash flows from operating activities in 1999 was primarily due to the completion of the recovery of SDG&E's stranded costs in 1999 and to reduced revenues (both the result of the sale of SDG&E's fossil power plants and combustion turbines in the second quarter of 1999) and a return to ratepayers of the previously overcollected regulatory balancing accounts of SoCalGas. This decrease was partially offset by the absence of business-combination expenses and lower income tax payments in 1999. See additional discussion on the sale of the power plants in Note 14 of the notes to Consolidated Financial Statements.

CASH FLOWS FROM INVESTING ACTIVITIES

For 2000, cash flows from investing activities included capital expenditures for utility plant and investments in South America.

For 1999, cash flows from investing activities included proceeds from the sale of SDG&E's two fossil power plants and combustion turbines. The South Bay Power Plant was sold to the San Diego Unified Port District for $110 million. The Encina Power Plant and 17 combustion-turbine generators were sold to Dynegy, Inc. and NRG Energy, Inc. for $356 million.

Capital Expenditures

Capital expenditures were $170 million higher in 2000 compared to 1999 due to investments in gas distribution facilities in the eastern United States, Canada and Mexico, expenditures for gas turbines, and improvements to SDG&E's electric distribution system and to the California utilities' gas systems.

Capital expenditures were $151 million higher in 1999 compared with 1998 due to investments in gas distribution facilities in Mexico, a gas system expansion at SDG&E and improvements to SDG&E's electric distribution system.

Capital expenditures in 2001 are expected to be comparable to those of 2000. They will include, among other things, capital expenditures for new power plant construction by SER and utility plant improvements. Capital expenditures for power plant construction are intended to be financed by debt issuances. The California utilities' capital expenditures are intended to be financed primarily by operations and debt issuances. SDG&E's capital expenditures are dependent on SDG&E's ability to recover its electricity costs, including the balancing account undercollections referred to above.

SER plans expenditures of up to $1.9 billion over the next five years related to new power plant construction.

Investments

During the three years ended December 31, 2000, the company made various investments and entered into several joint ventures. These include, among others, SEI's additional investment in two Argentinean natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.) of $147 million in October 2000. In August 2000, Sempra Energy Solutions (SES) purchased Connectiv Thermal Systems' 50-percent interests in both Atlantic-Pacific Las Vegas and Atlantic-Pacific Glendale for $40 million, thereby acquiring full ownership of these companies. In September 2000, the company acquired a majority interest in Atlantic Electric and Gas in the United Kingdom for $8 million and, in July 1998, purchased a subsidiary of Consolidated Natural Gas for $36 million.

In June 1999, SEI and PSEG Global (PSEG) jointly purchased 90 percent of Chilquinta Energia S.A. (Energia) at a total cost of $840 million. With the January 2000 joint purchase of an additional 9.75 percent, the companies jointly and equally hold 99.98 percent of Energia. In September 1999, the company and PSEG completed their acquisition of 47.5 percent of Luz del Sur S.A.A. SEI's share of the transaction was $108 million. This acquisition, combined with the interest already owned through Energia, increased the companies' total joint and equal ownership to 84.5 percent of Luz del Sur S.A.A.

Sempra Energy's level of investments in the next few years may vary substantially and will depend on the availability of financing and business opportunities that are expected to provide desirable rates of return.

See further discussion of international operations in "International

Operations" below and further discussion of investing activities in Note 3 of the notes to Consolidated Financial Statements.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash was provided by financing activities in 2000 compared to being used in 1999, due to the issuance of long-term and short-term debt in 2000 (excluding that related to the repurchase of common stock), and lower common stock dividends.

Net cash used in financing activities decreased in 1999 from 1998 levels primarily due to lower long-term and short-term debt repayments, greater long-term and short-term debt issuances and the repurchase of preferred stock in 1998.

Long-Term and Short-Term Debt

In 2000, the company issued $500 million of long-term notes and $200 million of mandatorily redeemable trust preferred securities to finance the repurchase of 36.1 million shares of its outstanding common stock. The company issued an additional $300 million of long-term notes during 2000 to reduce short-term debt. The increase in short-term debt primarily represents borrowings through Sempra Energy Global Enterprises (Global), a holding company for many of the company's subsidiaries, to finance the construction of gas distribution systems by SEI; and borrowings by SET to finance increased trading activities. Repayments on long-term debt in 2000 included $10 million of first-mortgage bonds, $65 million of rate-reduction bonds and $51 million of unsecured debt. In addition, during December 2000, $60 million of variable-rate industrial development bonds were put back by the holders and subsequently remarketed in February 2001 at a 7.0 percent fixed interest rate. Between January 24 and February 5, 2001, the company drew down substantially all ($1.3 billion) of its available credit facilities.

In 1999, repayments on long-term debt included $28 million of first-mortgage bonds, $66 million of rate-reduction bonds and $82 million of unsecured notes. The long-term debt issued in 1999 related primarily to the purchase of Energia. See additional discussion in Note 3 of the notes to Consolidated Financial Statements. The increase in short-term debt primarily represents borrowing through Global to finance a portion of SEI's acquisitions.

In 1998, cash was used for the repayment of $247 million of first-mortgage bonds and $66 million of rate-reduction bonds. Short-term debt repayments included repayment of $94 million of debt issued to finance SoCalGas' Comprehensive Settlement as discussed in Note 14 of the notes to Consolidated Financial Statements.

Stock Purchases and Redemptions

As noted above, the company repurchased 36.1 million shares of its common stock at a price of $20.00 per share in 2000. In March 2000, the company's board of directors authorized the optional expenditure of up to $100 million to repurchase additional shares of common stock from time to time in the open market or in privately negotiated transactions. Through December 31, 2000, the company acquired 162,000 shares under this authorization (all in July 2000). In 1998 the company repurchased $1 million of common stock. There were no common stock repurchases in 1999.

On February 2, 1998, SoCalGas redeemed all outstanding shares of its 7.75% Series Preferred Stock at a cost of $25.09 per share, or $75 million including accrued dividends.

Dividends

Dividends paid on common stock amounted to $244 million in 2000, compared to $368 million in 1999 and $325 million in 1998. The decrease in 2000 is due to a reduction in the quarterly dividend to $0.25 per share ($1.00 annualized rate) from its previous level of $0.39 per share ($1.56 annualized rate) and the previously mentioned stock repurchase. The increase in 1999 was the result of the company's paying dividends on its common stock at the rate previously paid by Enova, which, on an equivalent-share basis, is higher than the rate previously paid by PE.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The California Public Utilities Commission's (CPUC) regulation of the California utilities' capital structure limits to $924 million the portion of the company's December 31, 2000, retained earnings that is available for dividends.

Capitalization

Total capitalization at December 31, 2000, was $7.1 billion. The debt-to-capitalization ratio was 59 percent at December 31, 2000. Significant changes in capitalization during 2000 include the increase in long-term debt and the issuance of mandatorily redeemable trust preferred securities to repurchase common stock.

Cash and Cash Equivalents

Cash and cash equivalents were $637 million at December 31, 2000. This cash is available for investment in domestic and international projects consistent with the company's strategic direction, the retirement of debt, the repurchase of common stock, the payment of dividends and other corporate purposes. However, as discussed above, funds available for these purposes may be limited by SDG&E's ability to recover from its customers on a current basis the full amount of the high electricity prices.

If the impacts of the high electricity costs on a current basis and the company's inability to bill customers for these costs are favorably resolved, the company anticipates that operating cash required in 2001 for common stock dividends and debt payments will be provided by cash generated from operating activities and existing cash balances. Cash required for capital expenditures will be provided by cash generated both from operating activities and from long-term and short-term debt issuances.

In addition to cash generated from ongoing operations, the company has credit agreements that permit short-term borrowings of up to $2.2 billion, of which $566 million is outstanding at December 31, 2000, and/or support its commercial paper. These agreements expire at various dates through 2002. Because of the ramifications of the high electric costs (as discussed in Notes 4 and 14 of the notes to Consolidated Financial Statements), between January 24 and February 5, 2001, the company drew down substantially all ($1.3 billion) of its available credit facilities.

In December 2000, Sempra Energy and certain affiliates filed shelf registrations for public offerings of up to $2.3 billion of certain securities guaranteed by Sempra Energy. As yet, no debt securities have been issued under these registration statements. For additional information see Notes 5 and 14 of the notes to Consolidated Financial Statements.

RESULTS OF OPERATIONS

Seasonality

SDG&E's electric sales volume generally is higher in the summer due to air-conditioning demands. Both California utilities' natural gas sales volumes generally are higher in the winter due to heating demands, although that difference is lessening as the use of natural gas to fuel electric generation increases. Sales volumes of the company's South American affiliates are also affected by seasonality, but the timing of its increases and decreases is opposite of those in California since the seasons are reversed in the Southern Hemisphere.

2000 Compared to 1999

Net income for 2000 increased to $429 million, or $2.06 per share of common stock, from $394 million, or $1.66 per share of common stock, in 1999.

The $35 million increase in net income was primarily due to higher earnings achieved by SET and, to a lesser extent, SEI and SER. This increase was partially offset by lower income generated from the California utility operations and higher interest expense. The lower income at the California utilities resulted primarily from the $50 million pretax write off described in Note 14 of the notes to Consolidated Financial Statements. See additional discussion in "California Utility Operations," "International Operations," "Trading Operations" and "Other Operations" below.

For the fourth quarter of 2000, net income was $95 million, or $0.47 per share of common stock, compared with $105 million, or $0.44 per share of common stock, for the fourth quarter of 1999. The decrease in earnings was primarily attributable to increased interest costs and income taxes, partially offset by higher earnings from the company's trading and generation operations. The increase in earnings per share was due to the decrease in weighted average shares for the fourth quarter of 2000 in comparison to the corresponding period in 1999, partially offset by the lower net income.

In 2000, book value per share decreased to $12.35 from $12.58 in 1999, due to the repurchase of 36.1 million shares of common stock in February 2000, at a price higher than book value.

1999 Compared to 1998

Net income for 1999 increased to $394 million, or $1.66 per share of common stock, from $294 million, or $1.24 per share of common stock, in 1998.

The increase was primarily attributable to higher net income at the California utilities as a result of the business-combination costs in 1998, and increased earnings from SET and, to a lesser extent, from SEF and SER.

In 1999, book value per share increased to $12.58 from $12.29 in 1998, primarily due to the settlement of quasi-reorganization issues. See additional discussion in Note 2 of the notes to Consolidated Financial Statements.

CALIFORNIA UTILITY OPERATIONS

To understand the operations and financial results of SoCalGas and SDG&E, it is important to understand the ratemaking procedures that they follow.

SoCalGas and SDG&E are regulated by the CPUC. It is the responsibility of the CPUC to determine that utilities operate in the best interests of their customers and have the opportunity to earn a reasonable return on investment. In 1996, California enacted legislation restructuring California's investor-owned electric utility industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce electric rates. The PX served as a wholesale power pool and the ISO scheduled power transactions and access to the transmission system.

A flawed electric-industry restructuring plan, electricity supply/demand imbalances, and legislative and regulatory responses, including the rate ceiling as described in "Factors Influencing Future Performance" below, have materially and adversely affected the timing of revenue collections by the company and related cash flows. Additional legislation passed in early 2001, as well as future legislation and regulatory actions concerning California's energy crisis, could have a significant impact on SDG&E's future operations, liquidity and financial results.

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. The CPUC currently is studying the issue of restructuring for sales to core customers and, as mentioned above, supply/demand imbalances are affecting the price of natural gas in California more than in the rest of the country because of California's dependence on natural gas fired electric generation due to air-quality considerations.

In connection with restructuring of the electric and natural gas industries, SDG&E and SoCalGas received approval from the CPUC for Performance-Based Ratemaking (PBR). Under PBR, income potential is tied to achieving or exceeding specific performance and productivity measures, rather than to expanding utility plant in a market where a utility already has a highly developed infrastructure.

See additional discussion of these situations under "Factors Influencing Future Performance" and in Note 14 of the notes to Consolidated Financial Statements.

The tables below summarize the California utilities' natural gas and electric volumes and revenues by customer class for the years ended December 31, 2000, 1999 and 1998.

GAS SALES, TRANSPORTATION & EXCHANGE
(Dollars in millions,
volumes in billion cubic feet)

	Gas Sales	Transportation & Exchange	Total

	Throughput	Revenue	Throughput	Revenue	Throughput	Revenue
2000:						
Residential	284	$2,446	3	$13	287	$2,459
Commercial and industrial	107	760	339	225	446	985
Utility electric generation	-	-	373	130	373	130
Wholesale	-	-	25	18	25	18
	391	$3,206	740	$386	1,131	3,592
Balancing accounts and other						(287)
Total						$3,305
1999:						
Residential	313	$2,091	3	$ 10	316	$2,101
Commercial and industrial	105	560	324	243	429	803
Utility electric generation	18	7*	218	83	236	90
Wholesale	-	-	23	11	23	11
	436	$2,658	568	$347	1,004	3,005
Balancing accounts and other						(94)
Total						$2,911
1998:						
Residential	304	$2,234	3	$ 11	307	$2,245
Commercial and industrial	102	571	329	277	431	848
Utility electric generation	57	9*	139	66	196	75
Wholesale	-	-	28	7	28	7
	463	$2,814	499	$361	962	3,175
Balancing accounts and other						(423)
Total						$2,752

*This consists of the interdepartmental margin on SDG&E's sales to its power plants prior to their sale in 1999.

ELECTRIC SALES
(Dollars in millions, volumes in million kWhs)

	2000		1999		1998	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
Residential	6,304	$ 730	6,327	$ 663	6,282	$ 637
Commercial	6,123	747	6,284	592	6,821	643
Industrial	2,614	310	2,034	154	3,097	233
Direct access	3,308	99	3,212	118	964	44
Street and highway lighting	74	7	73	7	85	8
Off-system sales	899	59	383	10	706	15
	19,322	1,952	18,313	1,544	17,955	1,580
Balancing accounts and other		232		274		285
Total	19,322	$2,184	18,313	$1,818	17,955	$1,865

2000 Compared to 1999

Natural gas revenues increased from $2.9 billion in 1999 to $3.3 billion in 2000, primarily due to higher prices for natural gas in 2000 (see discussion of balancing accounts in Note 2 of the notes to Consolidated Financial Statements) and higher utility electric generation (UEG) revenues. The increase in UEG revenues was due to higher demand for electricity in 2000 and the sale of SDG&E's fossil fuel generating plants in the second quarter of 1999. Prior to the plant sale, SDG&E's natural gas revenues from these plants consisted of the margin from the sales. Subsequent to the plant sale, SDG&E gas revenues consist of the price of the natural gas transportation service since the sales now are to unrelated parties. In addition, the generating plants receiving gas transportation from the California utilities are operating at higher capacities than previously, as discussed below.

Electric revenues increased from $1.8 billion in 1999 to $2.2 billion in 2000. The increase was primarily due to higher sales to industrial customers and the effect of higher electric commodity costs, partially offset by the $50 million pretax charge at SDG&E for a potential regulatory disallowance related to the acquisition of wholesale power in the deregulated California market, and the decrease in base electric rates (the noncommodity portion) from the completion of stranded cost recovery. For 2000, SDG&E's electric revenues included an undercollection of $447 million as a result of the 6.5-cent rate cap. In January 2001, SDG&E filed with the CPUC for a temporary electric surcharge to reduce the growing undercollection of electric commodity costs. SDG&E is unable to predict the amount, if any, of the request that the CPUC would grant, or when it would issue a decision. The CPUC has deferred this proceeding pending resolution of the broader issues related to the state-wide high costs. Additional information concerning electric rates is described in "Factors Influencing Future Performance" below and in Note 14 of the notes to Consolidated Financial Statements.

The cost of natural gas distributed increased from $1.2 billion in 1999 to $1.6 billion in 2000. The increase was largely due to higher prices for natural gas. Prices for natural gas have increased due to the increased use of natural gas to fuel electric generation, colder winter weather, and population growth in California. Under the current regulatory framework, changes in core-market natural gas prices do not affect net income, since the actual commodity cost of natural gas for core customers is included in customer rates on a substantially current basis.

The cost of electric fuel and purchased power increased from $0.5 billion in 1999 to $1.3 billion in 2000. The increase was primarily due to the higher cost of electricity from the PX that has resulted from higher demand for electricity and the shortage of power plants in California, higher prices for natural gas used to generate electricity (as described above), the sale of SDG&E's fossil fuel generating plants and warmer weather in California. Additional information concerning the recent supply/demand conditions is provided in Note 14 of the notes to Consolidated Financial Statements. Under the current regulatory framework, changes in on-system prices normally do not affect net income. See the discussions of balancing accounts and electric revenues in Note 2 of the notes to Consolidated Financial Statements.

PX/ISO power revenues have been netted against purchased-power expense. In September 2000, as a result of high electricity costs the CPUC authorized SDG&E to purchase up to 1,900 megawatts of power directly from third-party suppliers under both short-term contracts and long-term contracts. Subsequent to December 31, 2000, the state of California authorized the DWR to purchase all of SDG&E's power requirements not covered by its own generation or by existing contracts. These and related events are discussed more fully in Note 14 of the notes to Consolidated Financial Statements.

Depreciation and amortization expense decreased from $0.8 billion in 1999 to $0.5 billion in 2000 and operating expenses decreased from $1.2 billion in 1999 to $1.1 billion in 2000. The decreases were primarily due to the 1999 sale of SDG&E's fossil fuel generating plants.

1999 Compared to 1998

Natural gas revenues increased from $2.8 billion in 1998 to $2.9 billion in 1999. The increase was primarily due to lower overcollections in 1999 and higher UEG revenues, partially offset by a decrease in residential, commercial and industrial revenues. The increase in UEG revenues was primarily due to the sale of SDG&E's fossil fuel generating plants in the second quarter of 1999, as explained above.

Electric revenues decreased from $1.9 billion in 1998 to $1.8 billion in 1999. The decrease was primarily due to a temporary decrease in base electric rates following the completion of SDG&E's stranded cost recovery as noted above and as more fully described in Note 14 of the notes to Consolidated Financial Statements.

The company's cost of natural gas distributed increased from $1.0 billion in 1998 to $1.2 billion in 1999. The increase was largely due to an increase in the average price of natural gas purchased.

Depreciation and amortization expense decreased from $0.9 billion in 1998 to $0.8 billion in 1999. The decrease was primarily due to the mid-1999 completion of the accelerated recovery of generation assets.

Operating expenses decreased from $1.3 billion in 1998 to $1.2 billion in 1999. The decrease was primarily due to the $117 million of business-combination costs in 1998.

TRADING OPERATIONS

SET, a leading natural gas, petroleum and power marketing firm headquartered in Stamford, Connecticut, was acquired on December 31, 1997. In addition to the transactions described below in "Market Risk," SET also enters into long-term structured transactions, such as the one supporting the SEI agreement referred to below in "International Operations." For the year ended December 31, 2000, SET recorded net income of $155 million compared to net income of $19 million in 1999. The increase in net income in 2000 compared to 1999 was primarily due to increased volatility in the U.S. natural gas and electric power markets, and higher trading volumes. In addition, European crude oil contributed significantly to SET's 2000 earnings. In 1998, a net loss of $13 million was recorded. The improvement in net income in 1999 compared to 1998 is due to greater penetration of all customer segments, resulting in higher volumes traded.

INTERNATIONAL OPERATIONS

SEI was formed in June 1998 to develop, operate and invest in energy-infrastructure systems and power-generation facilities outside the United States. SEI now has interests in natural gas and/or electric transmission and distribution projects in Argentina, Canada, Chile, Mexico, Peru and Uruguay, and is pursuing other projects in Latin America.

In February 2001, SEI announced plans to construct a $350 million, 600-megawatt power plant near Mexicali, Mexico. Construction of the project, named Termoelectrica de Mexicali, is expected to begin in mid-2001, with completion anticipated by mid-2003.

As noted above in "Investments," SEI increased its investment in Sodigas Pampeana S.A. and Sodigas Sur S.A. in 2000 and 1998. These natural gas distribution companies serve 1.3 million customers in central and southern Argentina, respectively, and have a combined sendout of 650 million cubic feet per day. See further discussion at Note 3 of the notes to Consolidated Financial Statements.

In June 2000, SEI, PG&E Corporation and Proxima Gas S.A de C.V. announced an agreement to construct a $230 million, 215-mile natural gas pipeline which will extend from Arizona to the Rosarito Pipeline south of Tijuana. The pipeline will have the capacity to transport 500 million cubic feet per day of natural gas. Construction of the pipeline is anticipated to begin in early 2002. Agreements have been signed for more than half of the capacity on the pipeline, with natural gas expected to begin flowing by September 2002.

As previously discussed, during 1999 and 2000 SEI and PSEG jointly purchased Energia and 84.5 percent of Luz del Sur S.A.A. See Note 3 of the Notes to Consolidated Financial Statements for a discussion of the acquisitions of Energia and Luz del Sur S.A.A.

In December 1999, Sempra Atlantic Gas (SAG), a subsidiary of SEI, was awarded a 25-year franchise by the provincial government of Nova Scotia to build and operate a natural gas distribution system in Nova Scotia. SAG has invested $23 million and plans to invest $700 million to $800 million over the next seven years to build the system, which will make natural gas available to 78 percent of the 350,000 households in Nova Scotia. Construction of the system began in the fourth quarter of 2000, with delivery of natural gas expected to begin in the second quarter of 2001.

SEI owns 60 percent of Distribuidora de Gas Natural de Mexicali, S. de R.L. de C.V. (DGN-Mexicali), that holds the first license awarded to a private company to build and operate a natural gas distribution system in Mexico. It plans to invest up to $25 million to provide service to

25,000 customers during the first five years of operation.

SEI owns 95 percent of Distribuidora de Gas Natural de Chihuahua, S. de R.L. de C.V. (DGN-Chihuahua), which distributes natural gas to the city of Chihuahua, Mexico and surrounding areas. On July 9, 1997, SEI's predecessor acquired ownership of a 16-mile transmission pipeline serving 20 industrial customers. SEI plans to invest nearly $50 million to provide service to 50,000 customers in the first five years of operation.

In May 1999, SEI was awarded a 30-year license to build and operate a natural gas distribution system in the La Laguna-Durango zone in north-central Mexico. SEI plans to invest over $40 million in the project during the first five years of operation.

In August 1998, SEI was awarded a 10-year agreement by the Mexican Federal Electric Commission to provide a complete energy-supply package for a power plant in Rosarito, Baja California through a joint venture. As noted above, SET acted as the trading company for the supply of natural gas. The contract includes provisions for delivery of up to 300 million cubic feet per day of natural gas, the related transportation services in the U.S., and construction of a 23-mile pipeline from the U.S.-Mexico border to the plant. Construction of the pipeline was completed in mid-2000 at a cost of $38 million, and SEI began supplying gas to the Rosarito Power Plant in July 2000. The pipeline will also serve as a link for a natural gas distribution system in Tijuana, Baja California, between San Diego and Rosarito.

Net income for international operations in 2000 was $33 million compared to net income of $2 million and a net loss of $4 million for 1999 and 1998, respectively. The increase in net income for 2000 was primarily due to the first full year of results from Luz del Sur S.A.A. and Energia, and improved operating results at Sodigas Pampeana S.A. and Sodigas Sur S.A. The increase in net income for 1999 was primarily due to income from Energia, and lower operating costs and increased sales (as a result of colder weather) in Argentina.

OTHER OPERATIONS

SER develops power plants for the competitive market, as well as owning natural gas storage, production and transportation assets. SER is planning to develop 5,000 to 10,000 megawatts of generation within the next decade in the Southwest, the Northeast, the Gulf States and the Midwest. SER is a 50-percent partner in El Dorado Energy, a 500-megawatt power plant located near Las Vegas, Nevada, which began commercial operation in 2000. SER recorded net income of $33 million, $5 million and $8 million in 2000, 1999 and 1998, respectively. The increase in net income for 2000 is primarily due to earnings from the El Dorado power plant.

SEF invests as a limited partner in affordable-housing properties and alternative-fuel projects. SEF's portfolio includes 1,300 properties throughout the United States. These investments are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF recorded net income of $28 million in both 2000 and 1999, and $20 million in 1998. SEF's future investment policy is dependent on the company's future income tax position.

SES provides integrated energy-related products and services to commercial, industrial, government, institutional and consumer markets. SES recorded net losses of $23 million, $11 million and $24 million in 2000, 1999 and 1998, respectively. These losses are primarily attributable to ongoing start-up costs.

OTHER INCOME, INTEREST EXPENSE AND INCOME TAXES

Other Income

Other income, which primarily consists of interest income from short-term investments, equity earnings from unconsolidated subsidiaries and interest on regulatory balancing accounts, increased to $106 million in 2000 from $50 million in 1999. The increase was primarily due to improved equity earnings from unconsolidated subsidiaries of SER and SEI, and higher balancing-account interest. Other income increased in 1999 to $50 million from $15 million in 1998, primarily due to increased equity earnings from SEI's unconsolidated subsidiaries.

Interest Expense

Interest expense for 2000 increased to $286 million in 2000 from $229 million in 1999. The increase was primarily due to interest expense incurred on long-term debt issued in connection with the company's common stock repurchase, as described in Notes 5 and 12 of the notes to the Consolidated Financial Statements, and on short-term commercial paper borrowings made in 2000. Interest expense for 1999 increased to $229 million from $197 million in 1998. This increase was primarily due to interest expense on the excess rate-reduction bond liability, as discussed in "Factors Influencing Future Performance" below.

Income Taxes

Income tax expense was $270 million, $179 million and $138 million for 2000, 1999 and 1998, respectively. The effective income tax rates were 38.6 percent, 31.2 percent and 31.9 percent for the same years. The increase in income tax expense for 2000 compared to 1999 was due to the increase in income before taxes combined with lower charitable contributions. (During 1999 SDG&E made a charitable contribution to the San Diego Unified Port District in connection with the sale of the South Bay generating plant.) The increase in income tax expense for 1999 compared to 1998 was due to the increase in income before taxes, partially offset by the charitable contribution to the San Diego Unified Port District. The effective income tax rates for 1998 and 1999 are not significantly different because the effect of leasing and other activities in 1998 was comparable to that of the 1999 charitable contribution.

FACTORS INFLUENCING FUTURE PERFORMANCE

Base results of the company in the near future will depend primarily on the results of the California utilities, while earnings growth and volatility will depend primarily on changes in the utility industry and activities at SEI, SET, SER and other businesses. The factors influencing future performance are summarized below.

Electric Industry Restructuring and Electric Rates

In 1996, California enacted legislation restructuring California's investor-owned electric utility industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce electric rates. During the transition period, utilities were allowed to charge frozen rates that were designed to be above current costs by amounts assumed to provide a reasonable opportunity to recover the above-market "stranded" costs of investments in electric-generating assets. The rate freeze was to end for each utility when it completed recovery of its stranded costs, but no later than March 31, 2002. SDG&E completed recovery of its stranded costs in June 1999 and, with its rates no longer frozen, SDG&E's overall rates were initially lower, but became subject to fluctuation with the actual cost of electricity purchases.

A number of factors, including supply/demand imbalances, resulted in abnormally high electric-commodity costs beginning in mid-2000 and continuing into 2001. During the second half of 2000, the average electric-commodity cost was 15.51 cents/kWh (compared to 4.15 cents/kWh in the second half of 1999). This caused SDG&E's monthly customer bills to be substantially higher than normal. In response, legislation enacted in September 2000 imposed a ceiling of 6.5 cents/kWh on the cost of electricity that SDG&E may pass on to its small-usage customers on a current basis. Customers covered under the commodity rate ceiling generally include residential, small-commercial and lighting customers. The ceiling, which was retroactive to June 1, 2000, extends through December 31, 2002 (December 31, 2003 if deemed by the CPUC to be in the public interest). As a result of the ceiling, SDG&E is not able to pass through to its small-usage customers on a current basis the full purchase cost of electricity that it provides. The legislation provides for the future recovery of undercollections in a manner (not specified in the decision) intended to make SDG&E whole for the reasonable and prudent costs of procuring electricity. In the meantime, the amount paid for electricity in excess of the ceiling (the undercollected costs) is accumulated in an interest-bearing balancing account. The undercollection, included in Regulatory Assets on the Consolidated Balance Sheets, was $447 million at December 31, 2000, and $605 million at January 31, 2001, and is expected to increase to $700 million in March 2001, and remain constant thereafter, except for interest, if the DWR continues to purchase SDG&E's power requirements, as more fully described in "California Utility Operations" herein. The rate ceiling has materially and adversely affected SDG&E's revenue collections and its related cash flows and liquidity. SDG&E has fully drawn upon substantially all of its short-term credit facilities. Its ability to access the capital markets and obtain additional financing has been substantially impaired by the financial distress being experienced by other California investor-owned utilities as well as by lender uncertainties concerning California utility regulation generally and the rapid growth of utility cost undercollections. Continued purchases by the DWR for resale to SDG&E's customers of substantially all of the electricity that would otherwise be purchased by SDG&E or dramatic decreases in wholesale electricity prices, favorable action by the CPUC on SDG&E's electric rate surcharge application and SDG&E's access to the capital markets are required to manage and finance SDG&E's cost undercollections and provide adequate liquidity.

Consequently, in January 2001, SDG&E filed an application with the CPUC requesting a temporary electric-rate surcharge of 2.3 cents/kWh, subject to refund, beginning March 1, 2001. The surcharge is intended to provide SDG&E with continued access to financing on commercially reasonable terms by managing the growth of SDG&E's undercollected power costs. The CPUC has deferred this proceeding, pending resolution of the broader issues related to the statewide high costs. In response to the situation facing the California IOUs, the state of California passed legislation to permit its governor to negotiate with the IOUs to acquire their transmission assets. SDG&E has been having discussions with representatives of the governor concerning the possibility of such a transaction and what its terms might be. There is no assurance that these discussions will result in a sale of the transmission assets. SDG&E would consider entering into such a transaction only if the sales price and conditions of the sale and of future operating arrangements are reasonable.

See additional discussion in Note 14 of the notes to Consolidated Financial Statements.

Natural Gas Restructuring and Gas Rates

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. In January 1998, the CPUC released a staff report initiating a proceeding 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's natural gas consumers. A CPUC decision is expected in 2001.

In October 1999, the state of California enacted a law that requires natural gas utilities to provide "bundled basic gas service" (including transmission, storage, distribution, purchasing, revenue-cycle services and after-meter services) to all core customers, unless the customer chooses to purchase gas from a nonutility provider. The law prohibits the CPUC from unbundling distribution-related gas services (including meter reading and billing) and after-meter services (including leak investigation, inspecting customer piping and appliances, pilot relighting and carbon monoxide investigation) for most customers. The objective is to preserve both customer safety and customer choice.

Supply/demand imbalances have increased the price of natural gas in California more than in the rest of the country because of California's dependence on natural gas fired electric generation due to air-quality considerations. The average price of natural gas at the California/Arizona (CA/AZ) border was $6.25/mmbtu in 2000, compared with $2.33/mmbtu in 1999. On December 11, 2000, the average spot-market price at the CA/AZ border reached a record high of $56.91/mmbtu. Underlying the high natural gas prices are several factors, including the increase in natural gas usage for electric generation, colder winter weather and reduced natural gas supply resulting from historically low storage levels, lower gas production and a major pipeline rupture. In December 2000, SDG&E and SoCalGas filed separately with the Federal Energy Regulatory Commission (FERC) for a reinstitution of price caps on short-term interstate capacity to the CA/AZ border and between the interstate pipelines and California's local distribution companies, effective until March 31, 2001. The FERC responded by issuing extensive data requests, but has not otherwise acted on the requests.

A recent lawsuit, which seeks class-action certification, alleges that Sempra Energy, SoCalGas, SDG&E and El Paso Energy Corp. acted to drive up the price of natural gas for Californians by agreeing to stop a pipeline project that would have brought new and cheaper natural gas supplies into California. Sempra Energy believes the allegations are without merit.

Electric-Generation Assets

El Dorado Energy (El Dorado), of which SER is a 50-percent partner, began commercial operations in May 2000 at its 500-megawatt power plant near Las Vegas, Nevada, generating energy to serve 350,000 households as discussed in "Other Operations" above. Its proximity to existing natural gas pipelines and electric transmission lines allows El Dorado to actively compete in the deregulated electric-generation market.

In December 2000, SER obtained approvals from the appropriate state agencies to construct the Elk Hills Power Project and the Mesquite Power Plant. The Elk Hills Power Project is a 550-megawatt power plant project near Bakersfield, California, in which SER will have a 50 percent interest. It is scheduled to begin construction in the second quarter of 2001 and to be operating in 2002. The plant is expected to generate energy to serve 350,000 households. The Mesquite Power Plant is a 1,200-megawatt project located near Phoenix, Arizona, which is scheduled to begin construction in the second quarter of 2001 and to be operating in 2003. The plant is expected to generate energy to serve 700,000 households.

Construction of the Termoelectrica de Mexicali power plant is expected to begin in mid-2001, with completion anticipated by mid-2003. The 600-megawatt power plant will be located near Mexicali, Mexico.

See additional discussion of these projects in Note 3 of the notes to Consolidated Financial Statements.

Investments and Joint Ventures

As discussed in "International Operations" above, the company has various investments, joint ventures and projects that will impact the company's future performance. These include, among other things, SEI's increased investment in two Argentinean natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.), SEI's investment in Energia and Luz del Sur S.A.A., construction of the Baja California pipelines, SEI's investments in several natural gas distribution systems in Mexico, the franchise awarded to SAG to build and operate a natural gas distribution system in Nova Scotia, and the investment in Atlantic Electric and Gas in the United Kingdom. See additional discussion of these investments, joint ventures and projects in Note 3 of the notes to Consolidated Financial Statements.

Performance-Based Regulation (PBR)

To promote efficient operations and improved productivity and to move away from reasonableness reviews and potential disallowances, the CPUC has been directing utilities to use PBR. PBR has replaced the general rate case and certain other regulatory proceedings for both SoCalGas and SDG&E. Under PBR, regulators require future income potential to be tied to achieving or exceeding specific performance and productivity goals, as well as cost reductions, rather than by relying solely on expanding utility plant in a market where a utility already has a highly developed infrastructure. See additional discussion of PBR in "California Utility Operations" above and in Note 14 of the notes to Consolidated Financial Statements.

Allowed Rate of Return

For 2001, SoCalGas is authorized to earn a rate of return on rate base of 9.49 percent and a rate of return on common equity of 11.6 percent, the same as in 2000 and 1999. SDG&E is authorized to earn a rate of return on rate base of 8.75 percent and a rate of return on common equity of 10.6 percent, compared to 9.35 percent and 11.6 percent, respectively, prior to July 1, 1999. Either utility can earn more than the authorized rate by controlling costs below approved levels or by achieving favorable results in certain areas, such as incentive mechanisms. In addition, earnings are affected by changes in sales volumes, except for the majority of SoCalGas' core sales.

Management Control of Expenses and Investment

In the past, management has been able to control operating expenses and investment within the amounts authorized to be collected in rates. However, that effort is now increasing. Due to the ever-increasing financial pressures experienced by SDG&E in the current electric industry environment, in January 2001 SDG&E launched a cash-conservation plan, which includes sales of nonessential property, containment of new hiring, reduction of outside contractors, and deferral of information system and construction projects that do not affect the core reliability of service to customers. While the company is not planning employee layoffs at this time, all expenses and activities not directly tied to the maintenance of essential services and safety will continue to be scrutinized and deferred if possible.

ENVIRONMENTAL MATTERS

The company's operations are subject to federal, state and local environmental laws and regulations governing such things as hazardous wastes, air and water quality, land use, solid-waste disposal, and the protection of wildlife.

Most of the environmental issues faced by the company occur at the California utilities. Utility capital costs to comply with environmental requirements are generally recovered through the depreciation components of customer rates. The utilities' customers generally are responsible for 90 percent of the noncapital costs associated with hazardous substances and the normal operating costs associated with safeguarding air and water quality, disposing properly of solid waste, and protecting endangered species and other wildlife. Therefore, the likelihood of the company's financial position or results of operations being adversely affected in a significant manner is remote.

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of the California utilities' manufactured-gas sites (21 completed as of December 31, 2000, and 24 to be completed), asbestos and other cleanup at SDG&E's former fossil fuel power plants (all sold in 1999 and actual or estimated cleanup costs included in the transactions), cleanup of third-party waste-disposal sites used by the company, which has been identified as a Potentially Responsible Party (investigations and remediations are continuing), and mitigation of damage to the marine environment caused by the cooling-water discharge from the San Onofre Nuclear Generating Station (the requirements for enhanced fish protection, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands are in process).

MARKET RISK

The company's policy is to use derivative financial instruments to reduce its exposure to fluctuations in interest rates, foreign-currency exchange rates and energy prices. The company also uses and trades derivative financial instruments in its energy trading and marketing activities. Transactions involving these financial instruments are with credit-worthy firms and major exchanges. The use of these instruments exposes the company to market and credit risks which, at times, may be concentrated with certain counterparties.

SET derives a substantial portion of its revenue from risk management and trading activities in natural gas, petroleum and electricity. Profits are earned as SET acts as a dealer in structuring and executing transactions that assist its customers in managing their energy-price risk. In addition, SET may, on a limited basis, take positions in energy markets based on the expectation of future market conditions. These positions include options, forwards, futures and swaps. See Note 10 of the notes to Consolidated Financial Statements and the following "Market-Risk Management Activities" section for additional information regarding SET's use of derivative financial instruments.

The California utilities periodically enter into interest-rate swap and cap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. These swap and cap agreements generally remain off the balance sheet since they involve the exchange of fixed-rate and variable-rate interest payments without the exchange of the underlying principal amounts. The related gains or losses are reflected in the income statement as part of interest expense. The company would be exposed to interest-rate fluctuations on the underlying debt should other parties to the agreement not perform. See the "Interest-Rate Risk" section below for additional information regarding the company's use of interest-rate swap and cap agreements.

The California utilities use energy derivatives to manage natural gas price risk associated with servicing their load requirements. In addition, they make limited use of natural gas derivatives for trading purposes. These instruments can include forward contracts, futures, swaps, options and other contracts, with maturities ranging from 30 days to 12 months. In the case of both price-risk management and trading activities, the use of derivative financial instruments by the California utilities is subject to certain limitations imposed by company policy and regulatory requirements. See Note 10 of the notes to Consolidated Financial Statements and the "Market-Risk Management Activities" section below for further information regarding the use of energy derivatives by the California utilities.

Market-Risk Management Activities

Market risk is the risk of erosion of the company's cash flows, net income and asset values due to adverse changes in interest and foreign-currency rates, and in prices for equity and energy. The company has adopted corporate-wide policies governing its market-risk management and trading activities. An Energy Risk Management Oversight Committee, consisting of senior officers, oversees company-wide energy-price risk management and trading activities to ensure compliance with the company's stated energy-risk management and trading policies. In addition, all affiliates have groups that monitor and control energy-price risk management and trading activities independently from the groups responsible for creating or actively managing these risks.

Along with other tools, the company uses Value at Risk (VaR) to measure its exposure to market risk. VaR is an estimate of the potential loss on a position or portfolio of positions over a specified holding period, based on normal market conditions and within a given statistical confidence level. The company has adopted the variance/covariance methodology in its calculation of VaR, and uses a 95-percent confidence level. Holding periods are specific to the types of positions being measured, and are determined based on the size of the position or portfolios, market liquidity, purpose and other factors. Historical volatilities and correlations between instruments and positions are used in the calculation. As of December 31, 2000, the VaR on the company's fixed-rate long-term debt and SET's portfolio were $314 million and $7.3 million, respectively, as more fully discussed below.

The following discussion of the company's primary market-risk exposures as of December 31, 2000, includes a discussion of how these exposures are managed.

Interest-Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its fixed-rate long-term debt. The company has historically funded utility 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 to take advantage of yield curves, or have used a combination of fixed-rate and floating-rate debt. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures when appropriate, based upon market conditions.

At December 31, 2000, the notional amount of interest-rate swap transactions associated with the regulated operations totaled $45 million. See Note 10 of the notes to Consolidated Financial Statements for further information regarding this swap transaction.

The VaR on the company's fixed-rate long-term debt is estimated at approximately $314 million as of December 31, 2000, assuming a one-year holding period.

Energy-Price Risk

Market risk related to physical commodities is based upon potential fluctuations in natural gas, petroleum and electricity prices and basis. The company's market risk is impacted by changes in volatility and liquidity in the markets in which these instruments are traded. The company's regulated and unregulated affiliates are exposed, in varying degrees, to price risk in the natural gas, petroleum and electricity markets. The company's policy is to manage this risk within a framework that considers the unique markets, and operating and regulatory environments of each affiliate.

Sempra Energy Trading

SET derives a substantial portion of its revenue from risk management and trading activities in natural gas, petroleum and electricity. As such, SET is exposed to price volatility in the domestic and international natural gas, petroleum and electricity markets. SET conducts these activities within a structured and disciplined risk management and control framework that is based on clearly communicated policies and procedures, position limits, active and ongoing management monitoring and oversight, clearly defined roles and responsibilities, and daily risk measurement and reporting.

Market risk of SET's portfolio is measured using a variety of methods, including VaR. SET computes the VaR of its portfolio based on the risk incurred in a one-day holding period. As of December 31, 2000, the diversified VaR of SET's portfolio was $7.3 million, compared to $2.6 million at December 31, 1999. The increased VaR results from the increased volatility and activity in the market in 2000 compared to 1999.

SDG&E and SoCalGas

The California utilities may, at times, be exposed to limited market risk in their natural gas purchase, sale and storage activities as a result of activities under SDG&E's gas PBR or SoCalGas' Gas Cost Incentive Mechanism. They manage their risk within the parameters of the company's market-risk management and trading framework. As of December 31, 2000, the total VaR of the California utilities' natural gas positions was not material.

Credit Risk

Credit risk relates to the risk of loss that would be incurred as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. The company avoids concentration of counterparties and maintains credit policies with regard to counterparties that management believes significantly minimize overall credit risk. These policies include an evaluation of prospective counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty.

The company monitors credit risk through a credit-approval process and the assignment and monitoring of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry.

Almost all of the California utilities' accounts receivable and significant portions of the accounts receivable of the company's other subsidiaries are with customers located in California and, therefore, potentially affected by the high costs of electricity and natural gas in California, as described above in "Factors Influencing Future Performance" and in Note 14 of the notes to Consolidated Financial Statements.

Foreign-Currency-Rate Risk

Foreign-currency-rate risk exists by the nature of the company's global operations. The company has investments in entities whose functional currency is not the U.S. dollar, which exposes the company to foreign-exchange movements, primarily in Latin American currencies. When appropriate, the company may attempt to limit its exposure to changing foreign-exchange rates through both operational and financial market actions. These actions may include entering into forward, option and swap contracts to hedge existing exposures, firm commitments and anticipated transactions. As of December 31, 2000, the company had not entered into any such arrangements.

NEW ACCOUNTING STANDARDS

Effective January 1, 2001, the company adopted Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities." As amended, SFAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position, measure those instruments at fair value and recognize changes in the fair value of derivatives in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposures.

The adoption of this new standard on January 1, 2001, did not have a material impact on the company's earnings. However, $1.1 billion in current assets, $1.1 billion in noncurrent assets, $6 million in current liabilities, and $238 million in noncurrent liabilities were recorded as of January 1, 2001, in the Consolidated Balance Sheet as fixed-priced contracts and other derivatives. Due to the regulatory environment in which SoCalGas and SDG&E operate, regulatory assets and liabilities were established to the extent that derivative gains and losses are recoverable or payable through future rates. As such, $1.1 billion in current regulatory liabilities, $1.1 billion in noncurrent regulatory liabilities, $5 million in current regulatory assets, and $238 million in noncurrent regulatory assets were recorded as of January 1, 2001, in the Consolidated Balance Sheet. The ongoing effects will depend on future market conditions and the company's hedging activities.

In December 1999, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin (SAB) 101 - Revenue Recognition. SABs are not rules issued by the SEC. Rather, they represent interpretations and practices followed by SEC staff in administering the disclosure requirements of the federal securities laws. SAB 101 provides guidance on the recognition, presentation and disclosure of revenue in financial statements; it does not change the existing rules on revenue recognition. SAB 101 sets forth the basic criteria that must be met before revenue should be recorded. Implementation of SAB 101 was required by the fourth quarter of 2000 and had no effect on the company's consolidated financial statements.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains statements that are not historical fact and constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, including statements regarding SDG&E's ability to finance undercollected costs on reasonable terms and retain its financial strength, estimates of future accumulated undercollected costs, and plans to obtain future financing. The words "estimates," "believes," "expects," "anticipates," "plans," "intends," "may," "would" and "should" or similar expressions, or discussions of strategy or of plans are intended to identify forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future results may differ materially from those expressed in these forward-looking statements.

Forward-looking statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others, local, regional, national and international economic, competitive, political, legislative and regulatory conditions; actions by the CPUC, the California Legislature, the DWR and the FERC; the financial condition of other investor-owned utilities; inflation rates and interest rates; energy markets, including the timing and extent of changes in commodity prices; weather conditions; business, regulatory and legal decisions; the pace of deregulation of retail natural gas and electricity delivery; the timing and success of business-development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company's business described in this Annual Report and other reports filed by the company from time to time with the SEC.

FIVE YEAR SUMMARY
At December 31 or for the years ended December 31
(Dollars in millions except per-share amounts)

	2000	1999	1998	1997	1996
REVENUES AND OTHER INCOME					
California utility revenues:					
Gas	$ 3,305	$ 2,911	$ 2,752	$ 2,964	$ 2,710
Electric	2,184	1,818	1,865	1,769	1,591
Other operating revenues	1,548	631	364	336	195
Other income	106	50	15	39	24
Total	$ 7,143	$ 5,410	$ 4,996	$ 5,108	$ 4,520
Income before interest and income taxes	$ 985	$ 802	$ 629	$ 927	$ 927
Net income	$ 429	$ 394	$ 294	$ 432	$ 427
Net income per common share:					
Basic	$ 2.06	$ 1.66	$ 1.24	$ 1.83	$ 1.77
Diluted	$ 2.06	$ 1.66	$ 1.24	$ 1.82	$ 1.77
Dividends declared per common share	$ 1.00	$ 1.56	$ 1.56	$ 1.27	$ 1.24
Pretax income/revenue	9.9%	10.7%	8.7%	14.5%	16.2%
Return on common equity	15.7%	13.4%	10.0%	14.7%	14.9%
Effective income tax rate	38.6%	31.2%	31.9%	41.1%	41.3%
Dividend payout ratio:					
Basic	48.5%	94.0%	125.8%	69.4%	70.1%

Diluted	48.5%	94.0%	125.8%	69.8%	70.1%
Price range of common shares	$24 7/8-$16 3/16	$26-$17 1/8	$29 5/16-$23 3/4	*	*
AT DECEMBER 31					
Current assets	$ 6,425	$ 3,015	$ 2,458	$ 2,761	$ 1,592
Total assets	$ 15,612	$11,124	$10,456	$10,756	$ 9,762
Current liabilities	$ 7,467	$ 3,236	$ 2,466	$ 2,211	$ 1,572
Long-term debt (excludes current portion)	$ 3,268	$ 2,902	$ 2,795	$ 3,175	$ 2,704
Shareholders' equity	$ 2,494	$ 2,986	$ 2,913	$ 2,959	$ 2,930
Common shares outstanding (in millions)	201.9	237.4	237.0	235.6	240.0
Book value per common share	$ 12.35	$ 12.58	$ 12.29	$ 12.56	$ 12.21
Price/earnings ratio	11.3	10.5	20.5	*	*
Number of meters (in thousands):					
Natural gas	5,807	5,726	5,639	5,551	5,501
Electricity	1,238	1,218	1,192	1,178	1,164

*Not presented as the formation of Sempra Energy was not completed until June 26, 1998.

Statement of Management's Responsibility
for Consolidated Financial Statements

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles. 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 auditors appointed by the board of directors. Their report is shown on the next page. 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 control which it believes is adequate to provide reasonable, but not absolute, assurance that assets are properly safeguarded, that transactions are executed in accordance with management's authorization and are properly recorded and that the accounting records may be relied on for the preparation of the consolidated financial statements, and for the prevention and detection of fraudulent financial reporting. The concept of reasonable assurance recognizes that the cost of a system of internal control should not exceed the benefits derived and that management makes estimates and judgments of these cost/benefit factors.

Management monitors the system of internal control for compliance through its own review and a strong internal auditing program, which independently assesses the effectiveness of the internal controls. In establishing and maintaining internal controls, the company must exercise judgment in determining whether the benefits derived justify the costs of such controls. Management believes that the company's system of internal control is adequate to provide assurance that the accompanying financial statements present fairly the company's financial position and results of operations.

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 of independent directors, to assist in fulfilling its oversight responsibilities for management's conduct of the company's financial reporting processes. The audit committee meets regularly to discuss financial reporting, internal controls and auditing matters with management, the company's internal auditors and independent auditors, and recommends to the board of directors any appropriate response to those discussions. The audit committee recommends for approval by the full board the appointment of 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.

/S/ NEAL E. SCHMALE   /S/ FRANK H. AULT

Neal E. Schmale
Executive Vice President and
Chief Financial Officer

Frank H. Ault
Vice President and Controller

Independent Auditors' Report

To the Board of Directors and Shareholders of Sempra Energy:

We have audited the accompanying consolidated balance sheets of Sempra Energy and subsidiaries (the "company") as of December 31, 2000 and 1999, and the related statements of consolidated income, cash flows and changes in shareholders' equity for each of the three years in the period ended December 31, 2000. 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 auditing standards generally accepted in the United States of America. 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, such consolidated financial statements present fairly, in all material respects, the financial position of Sempra Energy and subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
January 26, 2001 (February 27, 2001 as to Notes 3, 4, 5 and 14)

STATEMENTS OF CONSOLIDATED INCOME

For the years ended December 31 (Dollars in millions, except per-share amounts)	2000	1999	1998
Revenues and Other Income			
California utility revenues:			
Natural gas	$ 3,305	$ 2,911	$ 2,752
Electric	2,184	1,818	1,865
Other operating revenues	1,548	631	364
Other income	106	50	15
Total	7,143	5,410	4,996
Expenses			
Cost of natural gas distributed	1,599	1,164	954
Electric fuel and net purchased power	1,326	536	437
Operating expenses	2,464	1,837	1,853
Depreciation and amortization	563	879	929
Franchise payments and other taxes	180	181	182
Preferred dividends of subsidiaries	11	11	12
Trust preferred distributions by subsidiary	15	-	-
Total	6,158	4,608	4,367
Income before interest and income taxes	985	802	629
Interest	286	229	197
Income before income taxes	699	573	432
Income taxes	270	179	138

Net income	$ 429	$ 394	$ 294
Weighted-average number of shares outstanding:			
Basic*	208,155	237,245	236,423
Diluted*	208,345	237,553	237,124
Net income per share of common stock (basic)	$ 2.06	$ 1.66	$ 1.24
Net income per share of common stock (diluted)	$ 2.06	$ 1.66	$ 1.24
Common dividends declared per share	$ 1.00	$ 1.56	$ 1.56

*In thousands of shares

See notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

At December 31 (Dollars in millions)	2000	1999
ASSETS		
Current assets:		
Cash and cash equivalents	$ 637	$ 487
Accounts receivable - trade	994	428
Accounts and notes receivable - other	213	124
Income taxes receivable	24	144
Energy trading assets	4,083	1,539
Inventories	145	147
Other	329	146
Total current assets	6,425	3,015
Investments and other assets:		
Regulatory assets	1,174	549
Nuclear-decommissioning trusts	543	551
Investments	1,288	1,164
Other assets	456	451
Total investments and other assets	3,461	2,715
Property, plant and equipment:		
Property, plant and equipment	11,889	11,127
Less accumulated depreciation and amortization	(6,163)	(5,733)
Total property, plant and equipment - net	5,726	5,394
Total assets	$15,612	$ 11,124

See notes to Consolidated Financial Statements.

At December 31 (Dollars in millions)	2000	1999
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	$ 568	$ 182
Accounts payable - trade	1,162	492
Accounts payable - other	117	54
Energy trading liabilities	3,619	1,365
Dividends and interest payable	124	154
Regulatory balancing accounts - net	830	346
Deferred income taxes	110	67
Current portion of long-term debt	368	155
Other	569	421
Total current liabilities	7,467	3,236

Long-term debt	3,268	2,902
Deferred credits and other liabilities:		
Customer advances for construction	56	72
Postretirement benefits other than pensions	152	147
Deferred income taxes	826	615
Deferred investment tax credits	101	106
Deferred credits and other liabilities	844	856
Total deferred credits and other liabilities	1,979	1,796
Preferred stock of subsidiaries	204	204
Mandatorily redeemable trust preferred securities	200	-
Commitments and contingent liabilities (Notes 3 and 13)		
SHAREHOLDERS' EQUITY		
Common stock	1,420	1,966
Retained earnings	1,162	1,101
Deferred compensation relating to ESOP	(39)	(42)
Accumulated other comprehensive income (loss)	(49)	(39)
Total shareholders' equity	2,494	2,986
Total liabilities and shareholders' equity	$15,612	$11,124

See notes to Consolidated Financial Statements.

STATEMENTS OF CONSOLIDATED CASH FLOWS

For the years ended December 31 (Dollars in millions)	2000	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 429	$ 394	$ 294
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	563	879	929
Portion of depreciation arising from sales of generating plants	-	(303)	-
Application of balancing accounts to stranded costs	-	(66)	(86)
Deferred income taxes and investment tax credits	258	86	(229)
Equity in (income) losses of unconsolidated subsidiaries and joint ventures	(62)	5	19
Customer refunds paid	(628)	-	-
Other - net	(88)	(61)	(161)
Net change in other working capital components	410	254	557
Net cash provided by operating activities	882	1,188	1,323
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	(759)	(589)	(438)
Investments and acquisitions of subsidiaries	(243)	(639)	(191)
Net proceeds from sales of generating plants	-	466	-
Other - net	78	(27)	(50)
Net cash used in investing activities	(924)	(789)	(679)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common stock dividends	(244)	(368)	(325)
Repurchase of common stock	(725)	-	(1)
Sale of common stock	12	3	35
Issuance of trust preferred securities	200	-	-
Redemption of preferred stock	-	-	(75)
Issuances of long-term debt	813	160	75
Payment on long-term debt	(238)	(270)	(431)
Increase (decrease) in short-term debt - net	386	139	(311)
Other	(12)	-	(1)

	2000	1999	1998
Net cash provided by (used in) financing activities	192	(336)	(1,034)
Increase (decrease) in cash and cash equivalents	150	63	(390)
Cash and cash equivalents, January 1	487	424	814
Cash and cash equivalents, December 31	$ 637	$ 487	$ 424

See notes to Consolidated Financial Statements.

For the years ended December 31
(Dollars in millions)

	2000	1999	1998
CHANGES IN OTHER WORKING CAPITAL COMPONENTS			
(Excluding cash and cash equivalents, short-term debt and long-term debt due within one year)			
Accounts and notes receivable	$(655)	$188	$ 90
Net trading assets	(290)	(73)	(71)
Income taxes	120	(171)	22
Regulatory balancing accounts	522	303	417
Other current assets	(181)	(23)	12
Accounts payable	733	25	77
Other current liabilities	161	5	10
Net change in other working capital components	$410	$254	$557
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	$297	$281	$211
Income tax payments, net of refunds	$104	$168	$366
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES			
Liabilities assumed for real estate investments	$ -	$ 34	$ 36

See notes to Consolidated Financial Statements.

STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
For the years ended December 31, 2000, 1999 and 1998

(Dollars in millions)

	Comprehensive Income	Common Stock	Retained Earnings	Deferred Compensation Relating to ESOP	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 1997		$1,849	$1,157	$(47)	$-	$2,959
Net income/comprehensive income	$294		294			294
Common stock dividends declared			(376)			(376)
Sale of common stock		34				34
Repurchase of common stock		(1)				(1)
Long-term incentive plan		1				1
Common stock released from ESOP				2		2
Balance at December 31, 1998		1,883	1,075	(45)	-	2,913
Net income	$394		394			394
Comprehensive income adjustment:						
Foreign-currency translation losses	(42)				(42)	(42)

Available-for-sale Securities	10				10	10
Pension	(7)				(7)	(7)
Comprehensive income	$355					
Common stock dividends declared			(368)			(368)
Quasi-reorganization adjustment (Note 2)		80				80
Sale of common stock		2				2
Long-term incentive plan		1				1
Common stock released from ESOP				3		3
Balance at December 31, 1999		1,966	1,101	(42)	(39)	2,986
Net income	$429		429			429
Comprehensive income adjustment:						
Foreign-currency translation Losses	(2)				(2)	(2)
Available-for-sale securities	(10)				(10)	(10)
Pension	2				2	2
Comprehensive income	$419					
Common stock dividends declared			(201)			(201)
Sale of common stock		11				11
Repurchase of common stock		(558)	(167)			(725)
Long-term incentive plan		1				1
Common stock released from ESOP				3		3
Balance at December 31, 2000		$1,420	$1,162	$ (39)	$ (49)	$2,494

See notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1. BUSINESS COMBINATION

Sempra Energy (the company) was formed as a holding company for Enova Corporation (Enova) and Pacific Enterprises (PE) in connection with a business combination of Enova and PE that was completed on June 26, 1998. As a result of the combination, each outstanding share of common stock of Enova was converted into one share of common stock of Sempra Energy, and each outstanding share of common stock of PE was converted into 1.5038 shares of common stock of Sempra Energy. The preferred stock and preference stock of the combining companies and their subsidiaries remained outstanding.

The Consolidated Financial Statements are those of the company and its subsidiaries and give effect to the business combination using the pooling-of-interests method and, therefore, are presented as if the companies were combined during all periods included therein.

Note 2. SIGNIFICANT ACCOUNTING POLICIES

Effects Of Regulation

The accounting policies of the company's principal subsidiaries, San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas), conform with generally accepted accounting principles for regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

SDG&E and SoCalGas prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," under which a regulated utility records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. Regulatory liabilities represent future reductions in rates for amounts due to customers. To the extent that portions of the utility operations were to be no longer subject to SFAS No. 71, or recovery was to be no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets and liabilities would be written off. In addition, SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," affects utility plant and regulatory assets such that a loss must be recognized whenever a regulator excludes all or part of an asset's cost from rate base. The application of SFAS No. 121 continues to be evaluated in connection with industry restructuring. Information concerning regulatory assets and liabilities is described below in "Revenues and Regulatory Balancing Accounts" and industry restructuring is described in Note 14.

Revenues and Regulatory Balancing Accounts

Revenues for the California utilities consist of deliveries to customers and the changes in regulatory balancing accounts. The amounts included in regulatory balancing accounts at December 31, 2000, represent net payables of $463 million and $367 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 1999, were net payables of $154 million and $192 million for SoCalGas and SDG&E, respectively.

Prior to 1998, fluctuations in California utility earnings from changes in the costs of fuel oil, purchased energy and natural gas, and consumption levels for electricity and the majority of natural gas were eliminated by balancing accounts authorized by the CPUC. However, as a result of California's electric-restructuring law, previous overcollections recorded in SDG&E's applicable balancing accounts were applied to recovery of prior generation costs (as described in Note 14), and fluctuations in certain costs and consumption levels can now affect earnings from electric operations. In addition, fluctuations in certain costs and consumption levels can affect earnings from the California utilities' gas operations. Additional information on regulatory matters is included in Note 14.

Sempra Energy Trading (SET) derives a substantial portion of its revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum and petroleum products. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles, and takes positions in energy markets based on the expectation of future market conditions. These positions include options, forwards, futures and swaps. SET adjusts these derivatives to market each month with gains and losses recognized in earnings. See "Trading Instruments" below and Note 10 for additional information. Other subsidiaries recognize revenue on a mark-to-market basis, as energy is delivered to customers or as installations of customer projects progress.

Regulatory Assets

Regulatory assets include SDG&E's undercollected electric-commodity costs accumulated due to the temporary rate ceiling imposed in mid-2000. Regulatory assets also include unrecovered premiums on early retirement of debt, postretirement benefit costs, deferred income taxes recoverable in rates and other expenditures that the utilities expect to recover in future rates. See Note 14 for additional information on the rate ceiling, industry restructuring and other regulatory matters.

Trading Instruments

Trading assets and trading liabilities are recorded on a trade-date basis at fair value and include option premiums paid and received, and unrealized gains and losses from exchange-traded futures and options, over-the-counter (OTC) swaps, forwards, and options. Unrealized gains and losses on OTC transactions reflect amounts which would be received from or paid to a third party upon settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under a master netting arrangement enforceable by law. Revenues are recognized on a trade-date basis and include realized gains and losses, and the net change in unrealized gains and losses.

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and are carried at fair value based on closing exchange quotations. Commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and are carried at fair value derived from dealer quotations and underlying commodity-exchange quotations. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates, as applicable. For long-dated forward transactions, where there are no dealer or exchange quotations, fair values are derived using internally developed valuation methodologies based on available market information. Where market rates are not quoted, current interest, commodity and volatility rates are estimated by reference to current market levels. Given the nature, size and timing of transactions, estimated values may differ from realized values. Changes in the fair value are recorded currently in income.

Inventories

Included in inventories at December 31, 2000, were $77 million of materials and supplies ($67 million in 1999), and $68 million of natural gas and fuel oil ($80 million in 1999). Materials and supplies are generally valued at the lower of average cost or market; fuel oil and natural gas are valued by the last-in first-out method.

Property, Plant and Equipment

This primarily represents the buildings, equipment and other facilities used by SoCalGas and SDG&E to provide natural gas and electric utility service.

The cost of utility plant includes labor, materials, contract services and related items, and an allowance for funds used during construction. The cost of retired depreciable utility plant, plus removal costs minus salvage value, is charged to accumulated depreciation. Information regarding electric industry restructuring and its effect on utility plant is included in Note 14. Utility plant balances by major functional categories at December 31, 2000, were: natural gas operations $7.2 billion, electric distribution $2.7 billion, electric transmission $0.8 billion, and other electric $0.4 billion. The corresponding amounts at December 31, 1999, were: natural gas operations $7.1 billion, electric distribution $2.5 billion, electric transmission $0.7 billion, and other electric $0.4 billion. Accumulated depreciation and decommissioning of natural gas and electric utility plant in service at December 31, 2000, were $4.1 billion and $2.0 billion, respectively, and at December 31, 1999, were $3.8 billion and $1.9 billion, respectively. Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. The provisions for depreciation as a percentage of average depreciable utility plant (by major functional categories) in 2000, 1999 and 1998, respectively were: natural gas operations 4.29, 4.32, 4.32, electric distribution 4.67, 4.69, 4.49, electric transmission 3.21, 3.50, 3.31, and other electric 8.33, 8.21, 6.29. See Note 14 for discussion of the sale of generation facilities and industry restructuring. The remaining cost amounts ($0.8 billion at December 31, 2000,and $0.4 billion at December 31, 1999) consist of various items of property at other consolidated entities, with various depreciation rates depending on the nature of the items.

Nuclear-Decommissioning Liability

Deferred credits and other liabilities at December 31, 2000, and 1999, include $162 million and $165 million, respectively, of accumulated decommissioning costs associated with SDG&E's interest in San Onofre Nuclear Generating Station (SONGS) Unit 1, which was permanently shut down in 1992. Additional information on SONGS Unit 1 decommissioning costs is included in Note 6. The corresponding liability for Units 2 and 3 is included in accumulated depreciation and amortization.

Foreign Currency Translation

The assets and liabilities of the company's foreign operations are generally translated into U.S. dollars at current exchange rates, and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments are reflected in a component of shareholders' equity ("accumulated other comprehensive income"). Foreign currency transaction gains and losses are included in consolidated net income.

Comprehensive Income

Comprehensive income includes all changes, except those resulting from investments by owners and distributions to owners, in the equity of a business enterprise from transactions and other events including, as applicable, foreign-currency translation adjustments, minimum pension liability adjustments and unrealized gains and losses on marketable securities that are classified as available-for-sale. At December 31, 1999, the company had one such investment, which increased in value during 1999. In October 2000, this investment was sold. These changes are reflected in the Statement of Consolidated Changes in Shareholders' Equity.

Quasi-Reorganization

In 1993, PE divested its merchandising operations and most of its oil and gas exploration and production business. In connection with the divestitures, PE effected a quasi-reorganization for financial reporting purposes, effective December 31, 1992. Certain of the liabilities established in connection with the quasi-reorganization were favorably resolved in November 1999, including unitary tax issues. Excess reserves of $80 million resulting from the favorable resolution of these issues were added to shareholders' equity at that time. Other liabilities established in connection with discontinued operations and the quasi-reorganization will be resolved in future years. Management believes the provisions established for these matters are adequate.

Use Of Estimates In The Preparation Of The Financial Statements

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

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with original maturities of three months or less at the date of purchase.

Basis Of Presentation

Certain prior-year amounts have been reclassified to conform to the current year's presentation.

New Accounting Standards

Effective January 1, 2001, the company adopted Statement of Financial Accounting Standards (SFAS) No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities." As amended, SFAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position, measure those instruments at fair value and recognize changes in the fair value of derivatives in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

The adoption of this new standard on January 1, 2001, did not have a material impact on the company's earnings. However, $1.1 billion in current assets, $1.1 billion in noncurrent assets, $6 million in current liabilities, and $238 million in noncurrent liabilities were recorded as of January 1, 2001, in the Consolidated Balance Sheet as fixed-priced contracts and other derivatives. Due to the regulatory environment in which SoCalGas and SDG&E operate, regulatory assets and liabilities were established to the extent that derivative gains and losses are recoverable or payable through future rates. As such, $1.1 billion in current regulatory liabilities, $1.1 billion in noncurrent regulatory liabilities, $5 million in current regulatory assets, and $238 million in noncurrent regulatory assets were recorded as of January 1, 2001, in the Consolidated Balance Sheet. The ongoing effects will depend on future market conditions and the company's hedging activities.

In December 1999, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin (SAB) 101 - Revenue Recognition. SABs are not rules issued by the SEC. Rather, they represent interpretations and practices followed by SEC staff in administering the disclosure requirements of the federal securities laws. SAB 101 provides guidance on the recognition, presentation and disclosure of revenue in financial statements; it does not change the existing rules on revenue recognition. SAB 101 sets forth the basic criteria that must be met before revenue should be recorded. Implementation of SAB 101 was required by the fourth quarter of 2000 and had no effect on the company's consolidated financial statements.

Note 3. ACQUISITIONS AND JOINT VENTURES

Sempra Energy International (SEI)

SEI is involved in several investments, joint ventures and projects. In October 2000, SEI increased its existing investment in two Argentinean natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.) from 21.5 percent to 43 percent by purchasing an additional interest for $147 million. In June 2000, SEI, PG&E Corporation and Proxima Gas S.A de C.V. announced a joint agreement to construct a $230 million, 215-mile natural gas pipeline which will extend from Arizona to the Rosarito Pipeline south of Tijuana.

In June 1999, SEI and PSEG Global (PSEG) each purchased a 50-percent interest in Chilquinta Energia S.A. (Energia). SEI invested $260 million for the purchase of stock and refinanced $160 million of Energia's long-term debt outstanding. In September 1999, SEI and PSEG completed their acquisition of 47.5 percent of the outstanding shares of Luz del Sur S.A.A., a Peruvian electric company. SEI's share of the transaction was $108 million in cash. Combined with the 37 percent already owned through Energia, the companies' total joint ownership of Luz del Sur S.A.A. increased to 84.5 percent. In December 1999, Sempra Atlantic Gas (SAG), a subsidiary of SEI, was awarded a 25-year franchise by the provincial government of Nova Scotia to build and operate a natural gas distribution system in Nova Scotia. SAG invested $23 million in 2000.

SEI and Proxima Gas S.A. de C.V., partners in the Mexican companies Distribuidora de Gas Natural (DGN) de Mexicali and Distribuidora de Gas Natural de Chihuahua, are the licensees to build and operate natural gas distribution systems in Mexicali and Chihuahua. SEI owns interests of 60 and 95 percent in the DGN-Mexicali and DGN-Chihuahua projects, respectively. In addition, SEI was awarded a 30year license to build and operate, through its subsidiary, DGN de La Laguna Durango, a natural gas distribution system in the La Laguna-Durango zone in north-central Mexico. Through 2000, DGN-Mexicali, DGN-Chihuahua and DGN de La Laguna Durango have invested $18 million, $38 million and $18 million, respectively.

In August 1998, SEI was awarded a 10-year agreement by the Mexican Federal Electric Commission to provide a complete energy-supply package for a power plant in Rosarito, Baja California through a joint venture. SET acted as the trading company for the supply of natural gas. The contract includes provisions for delivery of up to 300 million cubic feet per day of natural gas, the related transportation services in the U.S., and construction of a 23-mile pipeline from the U.S.-Mexico border to the plant. Construction of the Rosarito pipeline was completed in mid-2000 at a cost of $38 million.

In February 2001, SEI announced plans to construct a $350 million, 600-megawatt power plant near Mexicali, Mexico. Construction is expected to begin in mid-2001, with completion anticipated by mid-2003.

Sempra Energy Trading (SET)

In April 2000, SET invested $4 million in Utility.com, the world's first Internet utility company. In July 1998, SET purchased CNG Energy Services Corporation, a subsidiary of Pittsburgh-based Consolidated Natural Gas Company, for $36 million.

Sempra Energy Resources (SER)

In December 2000, SER obtained approvals from the appropriate state agencies to construct the Elk Hills Power Project and the Mesquite Power Plant. The Elk Hills Power Project is a $360 million, 550-megawatt power plant near Bakersfield, California. Mesquite Power is a $630 million, 1200-megawatt project located near Phoenix, Arizona. In mid-2000, El Dorado Energy, a partnership between SER and Reliant Energy Power Generation, completed construction of a $280 million, 500-megawatt merchant power plant near Las Vegas, Nevada.

Sempra Energy Solutions (SES)

In August 2000, SES purchased Connectiv Thermal Systems' 50-percent interests in Atlantic-Pacific Las Vegas and Atlantic-Pacific Glendale for $40 million, thereby acquiring full ownership of these companies. In January 1998, SES completed the acquisition of CES/Way International (renamed Sempra Energy Services in 1999).

Note 4. SHORT-TERM BORROWINGS

At December 31, 2000, SoCalGas had a $200 million credit agreement, which was available to support commercial paper. At December 31, 2000, and 1999, SoCalGas' lines of credit were unused. On February 9, 2001, the agreement expired and was replaced on February 27, 2001, with a $170 million, one-year agreement. This agreement bears interest at various rates based on market rates and SoCalGas' credit rating.

At December 31, 2000, SDG&E had $285 million of bank lines available to support commercial paper and variable-rate long-term debt. The credit agreements expire at varying dates in mid-2001, but $200 million of the then outstanding borrowings may be extended at SDG&E's option to a term maturity of an additional year. Any debt under the lines would bear interest at various rates based on market rates and SDG&E's credit rating. SDG&E's bank lines of credit were unused at both December 31, 2000, and 1999.

At December 31, 2000, Sempra Energy Global Enterprises (Global), formerly Sempra Energy Holdings, the intermediate holding company for many of the company's subsidiaries, had a $1.2 billion credit agreement that expires in September 2001 and is extendable at Global's option for an additional year. Borrowings under the agreement bear interest at various rates based on market rates and the credit rating of Sempra Energy. Global's credit agreement is available to support commercial paper and variable-rate, long-term debt. Borrowings and the commercial paper are guaranteed by Sempra Energy. Global had $401 million and $182 million of commercial paper outstanding at December 31, 2000, and 1999, respectively.

Between January 24 and February 5, 2001, the company drew down substantially all ($1.3 billion) of the above credit facilities.

SET has $499 million in various uncommitted lines of credit that expire at varying dates in 2001 and bear interest at various rates based on market rates and the credit rating of SET. At December 31, 2000, SET had $165 million in short-term borrowings outstanding.

Note 5. LONG-TERM DEBT

December 31 (Dollars in millions)	2000	1999
Long-Term Debt		
First-mortgage bonds		
7.625% June 15, 2002	$ 28	$ 28
6.875% August 15, 2002	100	100
5.75% November 15, 2003	100	100
6.8% June 1, 2015	14	14
5.9% June 1, 2018	68	68
5.9% September 1, 2018	93	93
6.1% and 6.4% September 1, 2018 and 2019	118	118
Variable rates September 1, 2020	58	58
5.85% June 1, 2021	60	60
8.75% October 1, 2021	150	150
8.5% April 1, 2022	10	10
7.375% March 1, 2023	100	100
7.5% June 15, 2023	125	125
6.875% November 1, 2025	175	175
Various rates December 1, 2027	165	225
9.625% April 15, 2020	-	10
Total	1,364	1,434
Rate-reduction bonds, various rates (payable annually through 2007)	461	526
Debt incurred to acquire limited partnerships, secured by real estate, at 6.8% to 9.0% payable annually through 2009	233	284
Notes payable, 6.95% and 7.95%, payable in 2005 and 2010	800	-
Various unsecured bonds at 5.67% to 6.38% or at variable rates (3.7% to 4.1% at December 31, 2000) payable from 2001 to 2028	467	495
Employee Stock Ownership Plan, at variable rates (6.80% at December 31, 2000) payable from 2001 to 2015	130	130
Variable rate debt (10.20% at December 31, 2000) payable from 2008 to 2011	160	160
Capitalized leases	37	43
Total	3,652	3,072
Less:		
Current portion of long-term debt	368	155
Unamortized discount on long-term debt	16	15
	384	170
Total	$3,268	$2,902

Excluding capital leases, which are described in Note 13, maturities of long-term debt are $368 million in 2001, $234 million in 2002, $277 million in 2003, $100 million in 2004, $94 million in 2005 and $2.5

billion thereafter. Although holders of variable-rate bonds may elect to redeem them prior to scheduled maturity, for purposes of determining the maturities listed above, since redeemed bonds are remarketed and are backed by long-term lines of credit, it is assumed the bonds will be held to maturity. SDG&E has CPUC authorization to issue an additional $938 million in short-term or long-term debt (see discussion under "Recent Shelf Registrations" below) and SoCalGas has CPUC authorization to issue an additional $455 million in long-term debt.

First-Mortgage Bonds

First-mortgage bonds are secured by a lien on substantially all utility plant. SDG&E and SoCalGas may issue additional first-mortgage bonds upon compliance with the provisions of their bond indentures, which permit, among other things, the issuance of an additional $2.2 billion of first-mortgage bonds as of December 31, 2000, subject to CPUC authorization (see discussion under "Recent Shelf Registrations" below).

During May 2000, the company called $10 million of first-mortgage bonds prior to scheduled maturity. During December 2000, $60 million of variable-rate first-mortgage bonds were put back by the holders and subsequently remarketed on February 1, 2001, at a 7.0 percent fixed interest rate.

Callable Bonds

At the company's option, certain bonds may be called at a premium, including $227 million of variable-rate bonds that are callable at various dates in 2001. Of the company's remaining callable bonds, $195 million are callable in 2001, $204 million in 2002 and $621 million in 2003.

Rate-Reduction Bonds

In December 1997, $658 million of rate-reduction bonds were issued on behalf of SDG&E at an average interest rate of 6.26 percent. These bonds were issued to facilitate the 10-percent rate reduction mandated by California's electric-restructuring law. See Note 14 for additional information. These bonds are being repaid over 10 years by SDG&E's residential and small-commercial customers via a charge on their electricity bills. These bonds are secured by the revenue streams collected from customers and are not secured by, or payable from, utility assets.

The sizes of the rate-reduction bond issuances were set so as to make the investor-owned utilities (IOUs) neutral as to the 10-percent rate reduction, and were based on a four-year period to recover stranded costs. Because SDG&E recovered its stranded costs in only 18 months (due to the greater-than-anticipated plant-sale proceeds), the bond sale proceeds were greater than needed. Accordingly, during the third quarter of 2000, SDG&E returned to its customers, via a combination of cash refunds and billing credits, $388 million of surplus bond proceeds in accordance with a June 8, 2000 CPUC decision. The bonds and their repayment schedule are not affected by this refund.

Unsecured Debt

Various long-term obligations totaling $1.3 billion are unsecured at December 31, 2000. In February 2000, the company issued $500 million of long-term 7.95 percent notes due in 2010 to partially finance the self-tender offer described in Note 12. In December 2000, the company issued an additional $300 million in long-term 6.95 percent notes due in 2005 in order to reduce short-term debt. Unsecured bonds totaling $124 million have variable-rate provisions. In July 2000, SoCalGas repaid $30 million of 8.75 percent medium-term notes upon maturity.

Recent Shelf Registrations

In December 2000, Sempra Energy and certain affiliates filed three shelf registrations. Sempra Energy, Global and other affiliates jointly filed a shelf registration for the public offering of up to $1.0 billion of certain securities, guaranteed by Sempra Energy. SDG&E filed a shelf registration for the public offering of up to $800 million of debt securities and requested CPUC authorization to incur additional indebtedness. On February 8, 2001, the CPUC approved SDG&E's financing application, but denied SDG&E authority to issue first-mortgage bonds beyond the $138 million previously authorized. SDG&E has requested a rehearing of this denial. PE and Sempra Energy jointly filed a shelf registration for the public offering of up to $500 million of debt securities of PE, guaranteed by Sempra Energy.

Any securities under these shelf registrations are offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933. At December 31, 2000, no debt securities were issued under these registration statements.

Debt Of Employee Stock Ownership Plan (ESOP) and Trust (Trust)

The Trust covers substantially all of SoCalGas' employees and is used to fund part of the retirement savings plan. The Trust was assumed by Sempra Energy on October 1, 1999, and participation in the ESOP was expanded to include employees of Sempra Energy and some of its unregulated affiliates effective January 1, 2000. In November 1999, the $130 million ESOP debt was refinanced using 15-year notes with a variable interest rate (6.80% at December 31, 2000 and 6.59% at December 31, 1999). The notes are repriced weekly and are subject to buyback, at the holder's option, depending on market demand. Consequently, the notes are classified as "current portion of long-term debt" on the Consolidated Balance Sheets. Interest on ESOP debt amounted to $9 million in 2000 and $6 million in both 1999 and 1998. Dividends used for debt service amounted to $3 million in 2000 and $5 million in both 1999 and 1998.

Interest-Rate Swaps

SDG&E periodically enters into interest-rate swap and cap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. At December 31, 2000, SDG&E had such an agreement, maturing in 2002, with underlying debt of $45 million.

Note 6. FACILITIES UNDER JOINT OWNERSHIP

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2000, are:

(Dollars in millions)

Project	SONGS	Southwest Powerlink
Percentage ownership	20	88
Utility plant in service	$ 63	$217
Accumulated depreciation and amortization	$ 32	$119
Construction work in progress	$ 5	$ 2

The company's share of operating expenses is included in the Statements of Consolidated Income. Participants in each project must provide their own financing. The amounts specified above for SONGS include nuclear production, transmission and other facilities. Certain substation equipment at SONGS is wholly owned by the company.

SONGS Decommissioning

Objectives, work scope and procedures for the future dismantling and decontamination of the SONGS units must meet the requirements of the Nuclear Regulatory Commission, the Environmental Protection Agency, the CPUC and other regulatory bodies.

The company's share of decommissioning costs for the SONGS units is estimated to be $449 million in current dollars, based on a cost study completed in 1998. Cost studies are updated every three years and approved by the CPUC. Rate recovery of decommissioning costs is allowed until the time that the costs are fully recovered. The amount accrued each year, which is currently being collected in rates, is based on the amount allowed by regulators. This amount is considered sufficient to cover the company's share of future decommissioning costs. Payments to the nuclear decommissioning trusts are expected to continue until SONGS is fully decommissioned, which is not expected to occur before 2022, or until sufficient funds have been collected.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures have been dismantled, and preparations have been made for major work to be performed in 2001 and beyond. That work will include dismantling, removal and disposal of all Unit 1 equipment and facilities (both nuclear and non-nuclear components), decontamination of the site and construction of an on-site storage facility for Unit 1 spent fuel. These activities are expected to be completed by 2008.

The amounts collected in rates are invested in externally managed trust funds. The securities held by the trust are considered available for sale and the trust is shown on the Consolidated Balance Sheets at market value. These values reflect unrealized gains of $158 million and $164 million at December 31, 2000, and 1999, respectively.

The Financial Accounting Standards Board (FASB) is reviewing the accounting for liabilities related to closure and removal of long-lived assets, such as nuclear power plants, including the recognition, measurement and classification of such costs. The FASB could require, among other things, that the company's future balance sheets include a liability for the estimated decommissioning costs, and a related increase in the carrying value of the asset.

Additional information regarding SONGS is included in Notes 13 and 14.

Note 7. INCOME TAXES

The reconciliation of the statutory federal income tax rate to the effective income tax rate is as follows:

For the years ended December 31	2000	1999	1998
Statutory federal income tax rate	35.0%	35.0%	35.0%
Depreciation	6.7	7.0	7.5
State income taxes - net of federal income tax benefit	6.6	6.6	7.4
Tax credits	(13.0)	(14.9)	(12.9)
Charitable contribution of plant	-	(4.4)	-
Other - net	3.3	1.9	(5.1)
Effective income tax rate	38.6%	31.2%	31.9%

The components of income tax expense are as follows:

(Dollars in millions)	2000	1999	1998
Current:			
Federal	$ (8)	$ 72	$278
State	(5)	21	89
Foreign	25	-	-
Total	12	93	367
Deferred:			
Federal	207	79	(165)
State	57	15	(58)
Foreign	(1)	-	-
Total	263	94	(223)
Deferred investment tax credits - net	(5)	(8)	(6)
Total income tax expense	$270	$179	$138

Accumulated deferred income taxes at December 31 result from the following:

(Dollars in millions)	2000	1999
DEFERRED TAX LIABILITIES:		
Differences in financial and tax bases of utility Plant	$ 804	$ 832
Balancing accounts and other regulatory assets	521	235
Partnership income	49	37
Other	276	118
Total deferred tax liabilities	1,650	1,222
DEFERRED TAX ASSETS:		
Investment tax credits	71	74
General business tax credit carryforward	113	46
Comprehensive Settlement (see Note 14)	26	42
Postretirement benefits	39	69

Other deferred liabilities	143	98
Restructuring costs	51	51
Other	271	160
Total deferred tax assets	714	540
Net deferred income tax liability	$ 936	$ 682

The net liability is recorded on the Consolidated Balance Sheets at December 31 as follows:

(Dollars in millions)	2000	1999
Current liability	$ 110	$ 67
Noncurrent liability	826	615
Total	$ 936	$ 682

The general business tax credit carryforwards expire in 2019 and 2020.

The company has not provided for U.S. income taxes on foreign subsidiaries' undistributed earnings ($104 million at December 31, 2000), which are expected to be reinvested indefinitely. It is not possible to predict the amount of U.S. income taxes that might be payable if these earnings are eventually repatriated.

Note 8. EMPLOYEE BENEFIT PLANS

The information presented below describes the plans of the company and its principal subsidiaries. In connection with the PE/Enova business combination described in Note 1, certain of these plans have been merged with similar plans or modified, and numerous participants have been transferred among plans of related entities. In connection with voluntary separations related to the business combination, the company recorded a $66 million special termination benefit and a settlement gain of $30 million in 1998.

During 2000, Sempra Energy and most of its subsidiaries participated in another voluntary separation program. As a result, the company recorded a $56 million special termination benefit, a curtailment credit of $2 million, and a settlement gain of $26 million in 2000.

Pension and Other Postretirement Benefits

The company sponsors several qualified and nonqualified pension plans and other postretirement benefit plans for its employees. Effective March 1, 1999, the Pacific Enterprises Pension Plan merged with the Sempra Energy Cash Balance Plan.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and the fair value of assets over the two years, and a statement of the funded status as of each year end:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2000	1999	2000	1999
WEIGHTED-AVERAGE ASSUMPTIONS AS OF DECEMBER 31:				
Discount rate	7.25% (1)	7.75%	7.75%	7.75%
Expected return on plan assets	8.00%	8.00%	7.85%	7.85%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%
Cost trend of covered health care charges	-	-	7.50% (2)	7.75% (2)
CHANGE IN BENEFIT OBLIGATION:				
Net benefit obligation at January 1	$1,962	$2,080	$555	$563
Service cost	41	48	11	15
Interest cost	153	142	37	40
Plan participants' contributions	-	-	-	3
Actuarial (gain) loss	114	(147)	(37)	(44)
Curtailments	(7)	-	5	-
Settlements	2	-	-	-
Special termination benefits	54	-	2	-

Gross benefits paid	(292)	(161)	(22)	(22)
Net benefit obligation at December 31	2,027	1,962	551	555
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	3,427	2,796	548	443
Actual return on plan assets	(247)	789	(25)	96
Employer contributions	22	3	14	28
Plan participants' contributions	-	-	-	3
Gross benefits paid	(292)	(161)	(22)	(22)
Fair value of plan assets at December 31	2,910	3,427	515	548
Funded status at December 31	883	1,465	(36)	(7)
Unrecognized net actuarial gain	(945)	(1,627)	(106)	(128)
Unrecognized prior service cost	55	66	(10)	(12)
Unrecognized net transition obligation	2	3	-	-
Net recorded liability at December 31	$ (5)	$(93)	$(152)	$(147)

(1) Discount rate decreased from 7.75% to 7.25%, effective March 1, 2000.
(2) Decreasing to ultimate trend of 6.50% in 2004.

The following table provides the amounts recognized on the Consolidated Balance Sheets at December 31:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2000	1999	2000	1999
Prepaid benefit cost	$ 75	$ 13	$ -	$ -
Accrued benefit cost	(80)	(106)	(152)	(147)
Additional minimum liability	(12)	(18)	-	-
Intangible asset	4	6	-	-
Accumulated other comprehensive income, pretax	8	12	-	-
Net recorded liability	$ (5)	$(93)	$(152)	$(147)

The following table provides the components of net periodic benefit cost (income) for the plans:

For the years ended December 31	Pension Benefits			Other Postretirement Benefits		
(Dollars in millions)	2000	1999	1998	2000	1999	1998
Service cost	$ 41	$ 48	$ 55	$ 11	$ 15	$ 13
Interest cost	153	142	148	37	40	36
Expected return on assets	(239)	(206)	(196)	(37)	(32)	(24)
Amortization of:						
Transition obligation	1	1	1	11	11	11
Prior service cost	6	6	6	(2)	(1)	(1)
Actuarial (gain) loss	(55)	(31)	(23)	(8)	2	-
Special termination benefits	54	-	63	2	-	3
Curtailment credit	(2)	-	-	-	-	-
Settlement credit	(26)	-	(30)	-	-	-
Regulatory adjustment	18	17	-	26	15	-
Total net periodic benefit cost (income)	$ (49)	$ (23)	$ 24	$ 40	$ 50	$ 38

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percent change in assumed health care cost trend rates would have the following effects:

(Dollars in millions)	1% Increase	1% Decrease

Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 8	$ (7)
Effect on the health care component of the accumulated other postretirement benefit obligation	$74	$(69)

Except for one nonqualified retirement plan, all pension plans had plan assets in excess of accumulated benefit obligations. For that one plan the projected benefit obligation and accumulated benefit obligation were $65 million and $51 million, respectively, as of December 31, 2000, and $67 million and $62 million, respectively, as of December 31, 1999.

Other postretirement benefits include retiree life insurance, medical benefits for retirees and their spouses, and Medicare Part B reimbursement for certain retirees.

Savings Plans

The company offers savings plans, administered by plan trustees, to all eligible employees. Eligibility to participate in the various employer plans ranges from one month to one year of completed service. Employees may contribute, subject to plan provisions, from one percent to 15 percent of their regular earnings. Employer contributions, after one year of completed service, are used to purchase shares of company stock. Employer contribution methods vary by plan, but generally the contribution is equal to 50 percent of the first 6 percent of eligible base salary contributed by employees. The employees' contributions, at the direction of the employees, are primarily invested in company stock, mutual funds, institutional trusts or guaranteed investment contracts. Employer contributions for the Sempra Energy and SoCalGas plans are partially funded by the employee stock ownership plan referred to below. Company contributions to the savings plans were $15 million in 2000, $14 million in 1999 and $14 million in 1998. The fair value of company stock held by the savings plan was $501 million at December 31, 2000, and $391 million at December 31, 1999.

Employee Stock Ownership Plan (ESOP)

All contributions to the Employee Stock Ownership Plan and Trust (Trust) are made by the company; there are no contributions made by the participants.

As the company makes contributions to the ESOP, the ESOP debt service is paid and shares are released in proportion to the total expected debt service. Compensation expense is charged and equity is credited for the market value of the shares released. Income tax deductions are allowed based on the cost of the shares. Dividends on unallocated shares are used to pay debt service and are applied against the liability. The Trust held 2.8 million and 2.9 million shares of Sempra Energy common stock, with fair values of $65.5 million and $51.1 million, at December 31, 2000, and 1999, respectively.

Note 9. STOCK-BASED COMPENSATION

Sempra Energy has stock-based compensation plans that align employee and shareholder objectives related to the long-term growth of the company. The company's long-term incentive stock-compensation plan provides for aggregate awards of nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, performance awards, stock payments or dividend equivalents.

In 1995, SFAS No. 123, "Accounting for Stock-Based Compensation," was issued. It encourages a fair-value-based method of accounting for stock-based compensation. As permitted by SFAS No. 123, the company adopted only its disclosure requirements and continues to account for stock-based compensation in accordance with the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."

In 1999 and 1998, 85,400 shares and 102,640 shares, respectively, of restricted company stock were awarded to officers. There were no new issues in 2000. Each award is subject to forfeiture after four years if certain corporate goals are not met. Holders of this stock have voting rights and receive dividends prior to the time the restrictions lapse if, and to the extent, dividends are paid on company stock. Compensation expense for the issuance of these restricted shares was approximately $1 million in 2000, $1 million in 1999 and $2 million in 1998.

In 2000, 1999 and 1998 Sempra Energy granted to officers and 175 key employees 4,339,000, 3,442,400 and 3,635,800 stock options, respectively. The option price is equal to the market price of common stock at the date of grant. The grants, which vest over a one to four-year period, include options with and without performance-based dividend equivalents. The stock options expire in 10 years from the date of grant. Compensation expense (or reduction thereof) for the stock option grants (all associated with the options with dividend equivalents) and similar awards was $14 million, ($13 million) and $12 million in 2000, 1999 and 1998, respectively.

Had compensation cost for the stock-based compensation plans been determined based on the fair value at the grant dates for awards under those plans, consistent with the method of SFAS No. 123, the company's net income (earnings per share) would have been $378 million ($1.59 per share) and $285 million ($1.20 per share) for 1999 and 1998, respectively. For 2000, the company's net income was not affected and remained at $429 million ($2.06 per share).

The plans permit the granting of dividend equivalents, which provide grantees the opportunity to receive some or all of the cash dividends that would have been paid on the shares since the grant date, depending on the degree, if any, by which certain corporate goals are met. For grants prior to July 1, 1998, payment of the dividend equivalents is also contingent upon exercise of the options and requires that the market value of the shares purchased exceeds the option price.

The following information is presented after conversion of PE stock into company stock as described in Note 1.

STOCK OPTION ACTIVITY

	Shares Under Option	Average Exercise Price	Options Exercisable at Year End
OPTIONS WITH DIVIDEND EQUIVALENTS			
December 31, 1997	2,486,217	$18.51	1,513,545
Granted	2,131,803	$25.23	
Exercised	(512,059)	$17.12	
Cancelled	(509,301)	$23.00	
December 31, 1998	3,596,660	$22.06	1,387,523
Granted	1,451,100	$21.00	
Exercised	(254,886)	$17.32	
Cancelled	(99,677)	$23.34	
December 31, 1999	4,693,197	$21.96	1,844,079
Exercised	(399,875)	$18.91	
Cancelled	(264,749)	$23.39	
December 31, 2000	4,028,573	$22.17	2,462,574
OPTIONS WITHOUT DIVIDEND EQUIVALENTS			
December 31, 1997	1,363,496	$19.08	1,363,496
Granted	1,503,997	$26.47	
Exercised	(596,629)	$15.72	
Cancelled	(240,632)	$29.78	
December 31, 1998	2,030,232	$24.28	523,661
Granted	1,991,300	$21.00	
Exercised	(12,781)	$15.20	
Cancelled	(55,746)	$23.25	
December 31, 1999	3,953,005	$22.67	1,019,056
Granted	4,339,000	$19.03	
Exercised	(329,313)	$19.10	
Cancelled	(397,271)	$25.07	
December 31, 2000	7,565,421	$20.61	1,659,244

Additional information on options outstanding at December 31, 2000, is as follows:

Range of Exercise Prices	Number of Shares	Average Remaining Life	Average Exercise Price

Outstanding options			
$12.80-$16.12	422,959	3.40	$15.10
$16.79-$21.00	8,203,611	8.34	$19.72
$24.10-$27.92	2,967,424	6.83	$25.91
	11,593,994	7.77	$21.14
Exercisable options			
$12.80-$16.12	422,959		$15.10
$16.79-$21.00	1,867,161		$19.96
$24.10-$27.92	1,831,698		$25.86
	4,121,818		$22.08

The fair value of each option grant (including dividend equivalents where applicable) was estimated on the date of grant using the modified Black-Scholes option-pricing model. Weighted average fair values for options granted in 2000, 1999 and 1998 were $3.07, $4.24 and $8.20, respectively.

The assumptions that were used to determine these fair values are as follows:

	2000	1999	1998
Stock price volatility	20%	19%	16%
Risk-free rate of return	6.8%	5.5%	5.6%
Annual dividend yield*	5.4%	6.11%	5.27%
Expected life	6 Years	6 Years	6 Years

*The assumed yield for the options that include dividend equivalents is zero.

Note 10. FINANCIAL INSTRUMENTS

Fair Value

The fair values of the company's financial instruments (cash, temporary investments, funds held in trust, notes receivable, investments in limited partnerships, dividends payable, short-term and long-term debt, customer deposits, mandatorily redeemable trust preferred securities, and preferred stock of subsidiaries) are not materially different from the carrying amounts, except for long-term debt, mandatorily redeemable trust preferred securities and preferred stock of subsidiaries. The carrying amounts and fair values of long-term debt were $3.7 billion and $3.6 billion, respectively, at December 31, 2000, and $3.1 billion and $3.0 billion, respectively, at December 31, 1999. Included in long-term debt are SDG&E's rate-reduction bonds. The carrying amounts and fair values of the bonds were $461 million and $462 million, respectively, at December 31, 2000, and $526 million and $511 million, respectively, at December 31, 1999. The carrying amounts and fair values of mandatorily redeemable trust preferred securities, at December 31, 2000, were $200 million and $188 million, respectively. There were no issues of the mandatorily redeemable trust preferred securities at December 31, 1999. The carrying amounts and fair values of subsidiaries' preferred stock were $204 million and $146 million, respectively, at December 31, 2000, and $204 million and $167 million, respectively, at December 31, 1999. The fair values of the long-term debt, preferred stock and mandatorily redeemable trust preferred securities were estimated based on quoted market prices for them or for similar issues. In addition, included in long-term debt were notes payable which had carrying amounts and fair values of $237 million and $188 million, respectively, at December 31, 2000. The fair values of these notes payable were estimated based on the present value of the future cash flows, discounted at rates available for similar notes with comparable maturities.

Off-Balance-Sheet Financial Instruments

The company's policy is to use derivative financial instruments to manage its exposure to fluctuations in interest rates, foreign-currency exchange rates and energy prices. Transactions involving these financial instruments expose the company to market and credit risks which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated. Additional information on this topic is discussed in Note 2.

Swap Agreements

The company periodically enters into interest-rate swap and cap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. These agreements generally remain off the balance sheet as they involve the exchange of fixed-rate and variable-rate interest payments without the exchange of the underlying principal amounts. The related gains or losses are reflected in the Statements of Consolidated Income as part of interest expense.

At December 31, 2000, and 1999, SDG&E had one interest-rate-swap agreement: a floating-to-fixed-rate swap associated with $45 million of variable-rate bonds maturing in 2002. SDG&E expects to hold this financial instrument to its maturity. This swap agreement has effectively fixed the interest rate on the underlying variable-rate debt at 5.4 percent. SDG&E would be exposed to interest-rate fluctuations on the underlying debt should the counterparty to the agreement not perform. Such nonperformance is not anticipated. This agreement, if terminated, would result in an obligation of $1.3 million at both December 31, 2000, and December 31, 1999. Additional information on this topic is included in Note 5.

Energy Derivatives

The company uses energy derivatives for price-risk management and trading purposes within certain limitations imposed by company policies and regulatory requirements. Information on derivative financial instruments of SoCalGas and SET is provided below. Other business units use energy derivatives to mitigate risk and better manage costs. These instruments include forward contracts, swaps, options and other contracts which have maturities ranging from 30 days to 12 months.

Southern California Gas Company

SoCalGas is subject to price risk on its natural gas purchases if its cost exceeds a 2 percent tolerance band above the benchmark price. This is discussed further in Note 14. SoCalGas becomes subject to price risk when positions are incurred during the buying, selling and storage of natural gas. As a result of its Gas Cost Incentive Mechanism (GCIM), SoCalGas 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 CPUC has approved the use of gas futures for managing risk associated with the GCIM. At December 31, 2000, unrealized gains associated with these activities totaled $72 million. These savings will be passed on to customers during the first quarter of 2001. At December 31, 1999, gains and/or losses from natural gas futures contracts were not material to the company's financial statements.

Sempra Energy Trading

SET derives a substantial portion of its revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum and petroleum products. It quotes bid and offer prices to other market makers and end users. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. In addition, it takes positions in energy markets based on the expectation of future market conditions. These positions may be offset with similar positions or may be offset in exchange traded markets. These positions include options, forwards, futures and swaps. These financial instruments represent contracts with counterparties whereby payments are linked to or derived from energy market indices or on terms predetermined by the contract, which may or may not be financially settled by SET. For the year ended December 31, 2000, substantially all of SET's derivative transactions were held for trading and marketing purposes.

SET marks these derivatives to market each month, with gains and losses recognized in earnings. These instruments are included in the Consolidated Balance Sheets as energy trading assets or liabilities. Certain instruments, such as swaps, are entered into and closed out within the same month. Net gains and losses on these derivative transactions are included in revenue and other income in the Statements of Consolidated Income.

Market risk arises from the potential for changes in the value of financial instruments resulting from fluctuations in natural gas, electricity, petroleum and petroleum products commodity exchange prices and basis. Market risk is also affected by changes in volatility and liquidity in markets in which these instruments are traded.

SET also carries an inventory of financial instruments. Since trading strategies depend on both market making and proprietary positions, given the relationships between instruments and markets, those activities are managed in concert in order to maximize trading profits.

SET's credit risk from financial instruments as of December 31, 2000, is represented by the positive fair value of financial instruments after consideration of collateral. Credit risk disclosures, however, relate to the net losses that would be recognized if all counterparties completely failed to perform their obligations. Options written do not expose SET to credit risk. Exchange-traded futures and options are not deemed to have significant credit exposure as the exchanges guarantee that every contract will be properly settled on a daily basis.

The following table approximates the counterparty credit quality and exposure expressed in terms of net replacement value (dollars in millions):

Counterparty credit quality:	Futures, forward and swap contracts	Purchased options	Total
AAA	$ 22	$ 9	$ 31
AA	344	7	351
A	1,008	221	1,229
BBB	995	124	1,119
Below investment grade	299	112	411
Exchanges	491	6	497
Total	$3,159	$479	$3,638

Financial instruments with maturities or repricing characteristics of 180 days or less, including cash and cash equivalents, are considered short-term and, therefore, the carrying values of these financial instruments approximate their fair values. SET's commodities owned, trading assets and trading liabilities are carried at fair value. Accordingly, SET has determined that all of its financial instruments are recorded at fair value.

Based on quarterly observations, the average fair values during 2000, for trading assets and trading liabilities which are considered financial instruments with off-balance-sheet risk, approximate $2.5 billion and $2.2 billion, respectively.

The carrying value of trading assets and trading liabilities approximates the following:

December 31 (Dollars in millions)	2000	1999
ENERGY TRADING ASSETS		
Unrealized gains on swaps and forwards	$2,647	$1,244
Due from trading counterparties	684	63
OTC commodity options purchased	653	108
Due from commodity clearing organization and clearing brokers	99	124
Total	$4,083	$1,539
ENERGY TRADING LIABILITIES		
Unrealized losses on swaps and forwards	$2,590	$1,210
OTC commodity options written	612	73
Due to trading counterparties	417	82
Total	$3,619	$ 1,365

Notional amounts do not necessarily represent the amounts exchanged by parties to the financial instruments and do not measure SET's exposure to credit or market risks. The notional or contractual amounts are used to summarize the volume of financial instruments, but do not reflect the extent to which positions may offset one another. Accordingly, SET is exposed to much smaller amounts.

The notional amounts of SET's financial instruments at December 31, 2000, were:

(Dollars in millions)	Total
Forwards and commodity swaps	$45,656
Options written	13,799
Options purchased	13,496
Futures and exchange options	3,117
Total	$76,068

Note 11. PREFERRED STOCK OF SUBSIDIARIES

Pacific Enterprises

December 31 (Dollars in millions except call price)	Call Price	2000	1999
Cumulative preferred without par value:			
$4.75 Dividend, 200,000 shares authorized and outstanding	$100.00	$20	$20
$4.50 Dividend, 300,000 shares authorized and outstanding	$100.00	30	30
$4.40 Dividend, 100,000 shares authorized and outstanding	$101.50	10	10
$4.36 Dividend, 200,000 shares authorized and outstanding	$101.00	20	20
$4.75 Dividend, 253 shares authorized and outstanding	$101.00	-	-
Total		$80	$80

All or any part of every series of presently outstanding PE preferred stock is subject to redemption at PE's option at any time upon not less than 30 days' notice, at the applicable redemption price for each series, together with the accrued and accumulated dividends to the date of redemption. All series have one vote per share and cumulative preferences as to dividends. PE is authorized to issue 10,000,000 shares of Preferred Stock and 5,000,000 shares of Class A Preferred Stock. No shares of Class A Preferred Stock are outstanding.

SoCalGas

December 31 (Dollars in millions)	2000	1999
Not subject to mandatory redemption:		
$25 par value, authorized 1,000,000 shares		
6% Series, 28,134 shares outstanding	$ 1	$ 1
6% Series A, 783,032 shares outstanding	19	19
Without par value, authorized 10,000,000 shares	-	-
Total	$20	$20

None of SoCalGas' series of preferred stock is callable. All series have one vote per share and cumulative preferences as to dividends. On February 2, 1998, SoCalGas redeemed all outstanding shares of 7.75% Series Preferred Stock at a price per share of $25 plus accrued dividends. The total cost to SoCalGas was approximately $75.3 million.

SDG&E

December 31(Dollars in millions except call price) Call Price 2000 1999

Not subject to mandatory redemption			
$20 par value, authorized 1,375,000 shares:			
5% Series, 375,000 shares outstanding	$24.00	$ 8	$ 8
4.50% Series, 300,000 shares outstanding	$21.20	6	6
4.40% Series, 325,000 shares outstanding	$21.00	7	7
4.60% Series, 373,770 shares outstanding	$20.25	7	7
Without par value:			
$1.70 Series, 1,400,000 shares outstanding	$25.85	35	35
$1.82 Series, 640,000 shares outstanding	$26.00	16	16
Total not subject to mandatory redemption		$79	$79
Subject to mandatory redemption			
Without par value: $1.7625 Series, 1,000,000 shares outstanding	$25.00	$25	$25

All series of SDG&E's preferred stock have cumulative preferences as to dividends. The $20 par value preferred stock has two votes per share on matters being voted upon by shareholders of SDG&E and a liquidation value at par, whereas the no-par-value preferred stock is nonvoting and has a liquidation value of $25 per share. SDG&E is authorized to issue 10,000,000 shares of no-par-value preferred stock (both subject to and not subject to mandatory redemption). All series are currently callable except for the $1.70 and $1.7625 series (callable in 2003). The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares per year from 2003 to 2007; the remaining 750,000 shares must be redeemed in 2008.

Mandatorily Redeemable Trust Preferred Securities

On February 23, 2000, a wholly owned subsidiary trust of the company issued 8,000,000 shares of preferred stock in the form of 8.90-percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). The QUIPS have cumulative preferences as to distributions, are nonvoting and have a par and liquidation value of $25 per share. Cash dividends are paid quarterly and the QUIPS mature on February 23, 2030, subject to extension to a date not later than February 23, 2049, and shortening to a date not earlier than February 23, 2015. The QUIPS are subject to mandatory redemption and the company has guaranteed payments to the extent that the trust does not have funds available to make distributions. The QUIPS are callable on or after February 23, 2005 and there are no sinking fund provisions. The QUIPS are reflected as "Mandatorily redeemable trust preferred securities" on the company's Consolidated Balance Sheets and cash dividend payments are shown as "Trust preferred distributions by subsidiary" on the company's Statements of Consolidated Income. Proceeds of this issuance, together with $500 million of long-term 7.95% notes due 2010 (see Note 5), were used to finance substantially all of the tender offer referred to in Note 12.

Note 12. SHAREHOLDERS' EQUITY AND EARNINGS PER SHARE

The only difference between basic and diluted earnings per share is the effect of common stock options. For 2000, 1999 and 1998, the effect of dilutive options was equivalent to an additional 190,000; 308,000; and 701,000 shares, respectively. This had no effect on earnings per share.

This calculation excludes options covering 6.6 million shares for 2000, and 3.3 million shares for 1999 and 1998 for which the exercise price was greater than the shares' market price.

The company is authorized to issue 750,000,000 shares of no-par-value common stock and 50,000,000 shares of Preferred Stock. Excluding shares held by the ESOP, there were 201,927,524 shares of common stock outstanding at December 31, 2000, compared to 237,408,051 shares at December 31, 1999.

Tender Offer

On February 25, 2000, the company completed a self-tender offer, purchasing 36.1 million shares of its outstanding common stock at $20 per share. In March 2000, the company's board of directors authorized the optional expenditure of up to $100 million to repurchase additional shares of common stock from time to time in the open market or in privately negotiated transactions. Through December 31, 2000, the company acquired 162,000 shares under this authorization (all in July 2000). In 1998 the company repurchased $1 million of common stock. There were no common stock repurchases in 1999.

Note 13. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The company buys natural gas under short-term and long-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. SoCalGas and SDG&E transport gas under long-term firm pipeline capacity agreements that provide for annual reservation charges. SoCalGas and SDG&E recover such fixed charges in rates.

SoCalGas has commitments for firm pipeline capacity under contracts with pipeline companies that expire at various dates through 2006. In 1998, SoCalGas restructured its long-term commodity contracts with suppliers of California offshore and Canadian gas. These contracts expire at the end of 2003. SDG&E has long-term natural gas transportation contracts with various interstate pipelines which expire on various dates between 2007 and 2023.

SDG&E had been involved in negotiations and litigation with four Canadian suppliers concerning contract terms and prices related to long-term natural gas supply contracts. In 1999, SDG&E settled with the last of the four suppliers, terminating the contract. SDG&E continues to purchase natural gas from one of the suppliers under terms of the settlement agreement. SDG&E purchases natural gas on a spot basis to fill its additional long-term pipeline capacity. SDG&E intends to continue using the long-term pipeline capacity in other ways as well, including the transport of replacement natural gas and the release of a portion of this capacity to third parties.

In connection with the new natural gas franchise for Nova Scotia, the company plans to build and operate a natural gas system providing service to 78 percent of the 350,000 households in Nova Scotia. Construction began in October 2000. Total capital expenditures are estimated to be $700 million to $800 million over the next seven years. See Note 3 for additional information.

At December 31, 2000, the future minimum payments under natural gas contracts were:

(Dollars in millions)	Storage and Transportation	Natural Gas
2001	$ 192	$1,376
2002	188	394
2003	191	279
2004	195	-
2005	190	-
Thereafter	249	-
Total minimum payments	$1,205	$2,049

Total payments under the contracts were $1.6 billion in 2000, and $1.3 billion in 1999 and 1998.

Purchased-Power Contracts

SDG&E buys electric power under several long-term contracts. The contracts expire on various dates between 2001 and 2025. Prior to the electric rate ceiling described in Note 14, the above-market cost of contracts was recovered from virtually all of SDG&E's customers. In general, the market value of these contracts was recovered by bidding them into the California Power Exchange (PX) and receiving revenue from the PX for bids accepted. As of January 1, 2001, SDG&E no longer bid those contracts into the PX in compliance with a FERC order prohibiting sales to the PX. Since then those contracts have been used to serve customers. In late 2000, SDG&E entered into additional contracts to serve customers instead of buying all of its power from the PX. On January 17, 2001, the California Assembly passed a bill (AB 1) to allow the California Department of Water Resources (DWR) to purchase power under long-term contracts for the benefit of California consumers. For additional discussion of this matter see Note 14.

At December 31, 2000, the estimated future minimum payments under the long-term contracts were:

(Dollars in millions)	
2001	$ 320
2002	223
2003	211
2004	162
2005	164
Thereafter	2,295
Total minimum payments	$3,375

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Total payments under the contracts were $257 million in 2000, $251 million in 1999 and $293 million in 1998.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2001 to 2040. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2 percent to 6 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company. The company also has long-term capital leases for its nuclear fuel and real property. Property, plant and equipment includes $92 million at December 31, 2000, and $83 million at December 31, 1999, related to these leases. The associated accumulated amortization is $55 million and $39 million, respectively.

At December 31, 2000, the minimum rental commitments payable in future years under all noncancellable leases were:

(Dollars in millions)	Operating Leases	Capitalized Leases
2001	$ 61	$26
2002	61	6
2003	77	3
2004	124	3
2005	105	2
Thereafter	285	3
Total future rental commitment	$713	43
Imputed interest (6% to 15%)		(6)
Net commitment		$37

During 2000, SER entered into agreements with a lessor to facilitate the development and leasing of several power generation projects. The lessor has an aggregate financing commitment from investors of $1.05 billion. SER, as construction agent for the lessor, is responsible for completing construction by specified completion dates. Upon completion of an individual project, SER is required to make lease payments to the lessor in an amount sufficient to provide a return to the investors. In 2005, SER has the option to extend the lease at fair market value, purchase the project at a fixed amount, or act as remarketing agent for the lessor to sell the project. If SER elects the remarketing option, it may be required to pay the lessor up to 85 percent of the project cost if the proceeds from remarketing are deficient to repay the investors.

Rent expense totaled $102 million in 2000, $108 million in 1999 and $105 million in 1998.

In connection with the quasi-reorganization described in Note 2, PE established reserves of $102 million to fair value operating leases related to its headquarters and other leases at December 31, 1992. The remaining amount of these reserves was $56 million at December 31, 2000. These leases are included in the above table.

Other Commitments and Contingencies

At December 31, 2000, the company had commitments of approximately $450 million for the development of power plant sites and the purchase of the related gas turbines.

At December 31, 2000, commitments for other capital expenditures were approximately $44 million.

Environmental Issues

The company's operations are subject to federal, state and local environmental laws and regulations governing hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. Significant costs are incurred to operate the facilities in compliance with these laws and regulations and these costs generally have been recovered in customer rates.

In 1994, the CPUC approved the Hazardous Waste Collaborative Memorandum account allowing utilities to recover their hazardous waste costs, including those related to Superfund sites or similar sites requiring cleanup. Recovery of 90 percent of cleanup costs and related third-party litigation costs and 70 percent of the related insurance-litigation expenses is permitted. In addition, the company has the opportunity to retain a percentage of any insurance recoveries to offset the 10 percent of costs not recovered in rates. Environmental liabilities that may arise are recorded when remedial efforts are probable and the costs can be estimated.

The company's capital expenditures to comply with environmental laws and regulations were $4 million in 2000, $2 million in 1999 and $1 million in 1998. The increase in 2000 is due to the installation of emission-control equipment on SDG&E's Rainbow compressor facility and the increase in activity at SEI and SAG. Compliance with these regulations over the next five years is not expected to be significant. The company has been associated with various sites, which may require remediation under federal, state or local environmental laws. The company is unable to determine fully the extent of its responsibility for remediation of these sites until assessments are completed. Furthermore, the number of others that also may be responsible, and their ability to share in the cost of the cleanup, is not known.

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of the California utilities' manufactured-gas sites (21 completed as of December 31, 2000, and 24 to be completed), asbestos and other cleanup at SDG&E's former fossil-fueled power plants (all sold in 1999 and actual or estimated cleanup costs included in the transactions), cleanup of third-party waste-disposal sites used by the company, which has been identified as a Potentially Responsible Party (investigations and remediations are continuing), and mitigation of damage to the marine environment caused by the cooling-water discharge from the San Onofre Nuclear Generating Station (the requirements for enhanced fish protection, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands are in process).

As discussed in Note 14, restructuring of the California electric utility industry has changed the way utility rates are set and costs are recovered. In 1998, the CPUC modified the Hazardous Waste Collaborative mechanism by providing that electric-generation-related cleanup costs be included in transition-cost recovery. The effect of this decision is that SDG&E's costs of compliance with environmental regulations may not be fully recoverable.

Nuclear Insurance

SDG&E and the co-owners of SONGS have purchased primary insurance of $200 million, the maximum amount available, for public-liability claims. An additional $9.3 billion of coverage is provided by secondary financial protection required by the Nuclear Regulatory Commission and provides for loss sharing among utilities owning nuclear reactors if a costly accident occurs. SDG&E could be assessed retrospective premium adjustments of up to $36 million in the event of a nuclear incident involving any of the licensed, commercial reactors in the United States, if the amount of the loss exceeds $200 million. In the event the public-liability limit stated above is insufficient, the Price-Anderson Act provides for Congress to enact further revenue-raising measures to pay claims, which could include an additional assessment on all licensed reactor operators.

Insurance coverage is provided for up to $2.8 billion of property damage and decontamination liability. Coverage is also provided for the cost of replacement power, which includes indemnity payments for up to three years, after a waiting period of 12 weeks. Coverage is provided primarily through mutual insurance companies owned by utilities with nuclear facilities. If losses at any of the nuclear facilities covered by the risk-sharing arrangements were to exceed the accumulated funds available from these insurance programs, SDG&E could be assessed retrospective premium adjustments of up to $4 million.

Department Of Energy Decommissioning

The Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the Department of Energy (DOE) nuclear fuel enrichment facilities. Utilities which have used DOE enrichment services are being assessed a total of $2.3 billion, subject to adjustment for inflation, over a 15-year period ending in 2006. Each utility's share is based on its share of enrichment services purchased from the DOE through 1992. SDG&E's annual assessment is approximately $1 million. This assessment is recovered through SONGS revenue.

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. Continued delays by the DOE can lead to increased cost of disposal, which could be significant. If this occurs and the company is unable to recover the increased costs from the federal government or from its customers, the company's profitability from SONGS would be adversely affected.

Litigation

A recent lawsuit, which seeks class-action certification, alleges that Sempra Energy, SoCalGas, SDG&E and El Paso Energy Corp. acted to drive up the price of natural gas for Californians by agreeing to stop a pipeline project that would have brought new and cheaper natural gas supplies into California. The company believes the allegations are without merit.

Various recent lawsuits, which seek class-action certification and which are expected to be consolidated, allege that company subsidiaries unlawfully manipulated the electric-energy market. The company believes the allegations are without merit.

Except for the matters referred to above, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses. Management believes that these matters will not have a material adverse effect on the company's results of operations, financial condition or liquidity.

Electric Distribution System Conversion

Under a CPUC-mandated program and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2000, the aggregate unexpended amount of this commitment was approximately $100 million. Capital expenditures for underground conversions were $26 million in 2000, $20 million in 1999 and $17 million in 1998.

Concentration Of Credit Risk

The company maintains credit policies and systems to minimize overall credit risk. These policies include, when applicable, an evaluation of potential counterparties' financial condition and an assignment of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry. SDG&E and SoCalGas grant credit to utility customers, substantially all of whom are located in their service territories, which together cover most of Southern California and a portion of central California.

Supply/demand imbalances have caused a significant increase in the price of electricity and, although there is currently a temporary ceiling on the cost of electricity that SDG&E may pass on to its customers, once SDG&E is able to pass on these costs, the company may experience an increase in customer credit risk. Additional information on this issue is discussed in Note 14.

SET monitors and controls its credit-risk exposures through various systems which evaluate its credit risk, and through credit approvals and limits. To manage the level of credit risk, SET deals with a majority of counterparties with good credit standing, enters into master netting arrangements whenever possible and, where appropriate, obtains collateral. Master netting agreements incorporate rights of setoff that provide for the net settlement of subject contracts with the same counterparty in the event of default.

Note 14. REGULATORY MATTERS

Electric Industry Restructuring

In 1996, California enacted legislation (AB 1890) restructuring California's investor-owned electric utility industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce electric rates.

As part of the framework for a competitive electric-generation market, the legislation established the PX. The PX served as a wholesale power pool to which the California IOUs were required to sell all of their power supply (including owned generation and purchased-power contracts) and, except to the extent otherwise authorized by the CPUC, from which they were required to buy all of the electricity needed to serve their retail consumers. The PX also purchased power from nonutility generators through an auction process intended to establish competitive market prices for the power that it sells to the IOUs.

The restructuring legislation also established a rate freeze on amounts that the IOUs could charge their customers. The rate freeze was designed to generate revenue levels assumed to be sufficient to provide the IOUs with a reasonable opportunity to recover, by December 31, 2001, their costs of generation and purchased power that are fixed and unavoidable and included in customer rates. Certain costs such as those related to purchased-power contracts (including those with qualifying facilities) may be recovered beyond December 31, 2001. The rate freeze was to end as to each utility when it completed recovery of the costs, but in no event later than March 31, 2002.

In June 1999, SDG&E completed the recovery of its stranded costs, other than the future above-market portion of its purchased-power contracts that were in effect at December 31, 1995, and SONGS costs, both of which will continue to be collected in rates. Recovery of the other costs was effected by, among other things, the sale of SDG&E's fossil power plants and combustion turbines during the quarter ended June 30, 1999. Therefore, SDG&E is no longer subject to the rate freeze imposed by AB 1890.

With the rate freeze no longer applicable, SDG&E lowered its base rates (the portion of its rates not attributable to electric-commodity costs) and began to pass through to its customers, without markup, the cost of electricity purchased from the PX. SDG&E's overall rates were lower than during the rate freeze, but they also became subject to fluctuation with the actual cost of electricity purchases.

A number of factors, including supply/demand imbalances, resulted in abnormally high electric-commodity prices beginning in mid-2000, which caused SDG&E's monthly customer bills to be substantially higher than normal. These conditions and the resultant abnormally high electric-commodity prices continued into 2001. During the second half of 2000, the average electric-commodity cost was 15.51 cents/kWh (compared to 4.15 cents/kWh in the second half of 1999). In December 2000, the average was 17.91 cents/kWh (compared to 3.73 cents/kWh in December 1999).

These higher prices were initially passed through to SDG&E's customers and resulted in customer bills that in most cases were double or triple those from the prior year. This resulted in legislative and regulatory responses.

California Assembly Bill 265 (AB 265), enacted in September 2000, imposes a ceiling of 6.5 cents/kWh on the cost of the electric commodity that SDG&E may pass on to its small-usage customers on a current basis. Customers covered under the commodity rate ceiling generally include residential, small-commercial and lighting customers. This is a "floating cap" that can float downward as prices decrease, but cannot exceed actual commodity costs without the permission of the CPUC. The ceiling, retroactive to June 1, 2000, extends through December 31, 2002, and may be extended through December 31, 2003, if the CPUC determines that it is in the public interest to do so. The legislation also provides for the future recovery of undercollections (the cost of electricity purchased by SDG&E that cannot be passed on to customers on a current basis) resulting from the reasonable and prudent costs of procuring the commodity. In accordance with AB 265, the CPUC is examining the prudence and reasonableness of SDG&E's procurement of wholesale energy on behalf of its customers for the period July 1999 through August 2000. A decision is expected in the third quarter of 2001. Based upon historical experience with the CPUC, SDG&E recorded a $50 million pretax charge during the third quarter of 2000 related to the recent legislative and regulatory actions associated with power acquisition costs.

SDG&E accumulates the amount that it pays for electricity in excess of the ceiling rate (the undercollected costs) in an interest-bearing balancing account. SDG&E expects to amortize these amounts, together with interest, in rates charged to customers following the end of the ceiling period. Due to their long-term nature, these undercollected costs are classified as a noncurrent regulatory asset on the company's Consolidated Balance Sheets. The undercollection was $447 million at December 31, 2000 and $605 million at January 31, 2001. The rate ceiling materially and adversely affects the timing of SDG&E's revenue collections and related cash flows. The rate at which the undercollected costs accumulate will depend primarily upon the effects of the recently enacted AB 1 discussed under "Purchased Power Contracts" in Note 13 and below under "Recent State of California Actions," and other legislative and regulatory developments, wholesale prices for electric power and, to a lesser extent, variations in the volume of electricity used by SDG&E's customers (which is significantly affected by seasonal and other temperature variations) and the availability, price and use of longer-term fixed-price purchase contracts. Because of these and many other factors, the amount of undercollected costs that will accumulate in future periods cannot be estimated with any reasonable certainty. However, as discussed below under "Recent State of California Actions," AB1 could end material growth in SDG&E's cost undercollections.

The rate ceiling has materially and adversely affected SDG&E's revenue collections and its related cash flows and liquidity. SDG&E has fully drawn upon substantially all of its short-term credit facilities. Its ability to access the capital markets and obtain additional financing has been substantially impaired by the financial distress being experienced by other California IOUs as well as by lender uncertainties concerning California utility regulation generally and the rapid growth of utility cost undercollections.

On January 24, 2001, SDG&E filed an application with the CPUC requesting a temporary 2.3 cents/kWh electric rate surcharge, subject to refund, beginning March 1, 2001. The surcharge is intended to provide SDG&E with continued access to financing on commercially reasonable terms by managing the growth of SDG&E's undercollected power costs and to provide for the amortization of the undercollections in customer rates. SDG&E's application also renews a previous request that the CPUC freeze the commodity rate SDG&E can charge its customers at 6.5 cents/kWh instead of using that rate as a ceiling. SDG&E is unable to predict the amount, if any, of the request that the CPUC would grant, or when it would issue a decision. The CPUC has deferred this proceeding pending resolution of the broader issues related to the state-wide high costs.

FERC Actions

On November 1, 2000, the FERC reported its findings from its formal investigation of the electric rates and structure of the ISO/PX, as well as of market-based sellers in the California market. The investigation found no specific abuse of market power by individual generators and determined that constraints within the market structure, such as hedging restrictions imposed by the CPUC, and a long-term shortage of power in the state, resulted in the high electric-commodity prices. Federal regulators proposed several remedies to fix California's flawed market, but stated that past profits from generators and traders could not be ordered refunded to customers. The FERC did state that the high short-term energy rates during the summer of 2000 were "unjust and unreasonable" and left the door open to future customer refunds should specific instances of market abuses be uncovered. The report proposed various remedies and on December 15, 2000, the FERC issued an order adopting these remedies. Among other things, the order allows the California IOUs to buy and sell power outside the PX to afford the IOUs more favorable pricing, to replace the ISO/PX stakeholder governing boards with independent boards, and to require market buyers to schedule 95 percent of their transactions in the day-ahead markets to reduce the over-reliance on the real-time market to meet supply.

The order fails to require sellers to enter into forward contracts at reasonable prices, fails to provide an effective price cap and does not address issues associated with retroactive refund and retroactive remedial authority issues. The IOUs have requested a rehearing, which is pending, of the FERC's decision based on insufficiency of remedies for the wholesale electric market situation.

In connection with reaction to the FERC order, the PX suspended its trading operations on January 31, 2001.

PX/ISO Billings

Although it has experienced substantial undercollections of its costs of purchasing electricity for its customers, SDG&E has nonetheless remained current in paying for its electricity purchases as well as its other payment obligations. However, on February 9, 2001, SDG&E received a "charge-back" billing of $29 million relating to a default by another California utility in paying for power purchased by the other utility from the Independent System Operator (ISO) that schedules power transactions and access to the transmission system. SDG&E believes the charge-back is improper under applicable tariffs. SDG&E and other recipients of the charge-back billings have obtained an order preventing their collection pending the outcome of litigation contesting the charges.

SDG&E may receive additional charge-back billings in respect to defaults in electricity purchase payments by other California IOUs in paying for electricity purchased from the ISO and the PX. It also expects that it may receive billings for its own purchases of electricity from the PX that do not reflect proper compliance by the PX with wholesale price caps ordered by the FERC. These billings are expected to cease in March 2001, since SDG&E is no longer selling electricity to the PX. SDG&E will contest all such billings to the extent that it believes they are inconsistent with applicable tariffs and orders.

Recent State of California Actions

Federal and California officials met with power generators, marketers and utility representatives several times in January 2001 to try to end California's power crisis. The parties conceptually agreed that, among other things, the state of California would buy electricity through long-term contracts at reduced rates, which it would resell to consumers. In order to implement these plans, the California Legislature passed AB 1, signed by the governor on February 1, 2001, to allow the DWR to purchase power via long-term contracts for resale to consumers. The bill authorizes the DWR to enter into long-term contracts of up to 10 years to purchase power and to sell it to consumers at not more than the acquisition costs. This authority ends on December 31, 2002. Repayment will come from utility customers' monthly bills. The bill also authorizes funds from the state's general fund for immediate power purchases and authorizes the DWR to issue up to $10 billion in revenue bonds to purchase power. Ratepayers will pay off these advances and bonds over time. The law also encourages energy conservation by prohibiting higher rates for customers that do not exceed 130 percent of a baseline allotment for energy consumption and setting penalties for businesses that don't reduce their outside lighting. The first state power auction was held in January 2001. In early February 2001, the DWR announced agreements on contracts totaling about 5,000 megawatts and ranging from three years to 10 years. The state is expected to purchase about one-third of the electricity used by the IOUs' customers. Also in early February 2001, the CPUC approved emergency regulations for delivery and payment mechanisms for the sale of electricity procured by the DWR. In an interim agreement between the DWR and SDG&E, effective February 7, 2001, the DWR is purchasing the entire portion of the power used by SDG&E customers that is not provided by SONGS or SDG&E's existing contracts.

SDG&E believes that the DWR's purchase of all of SDG&E's power needs would end material growth in SDG&E's cost undercollections. To the extent that the DWR does not purchase all of SDG&E's power needs, SDG&E may be required to begin again making purchases and to purchase any shortfall at market prices for resale to its customers at SDG&E's ceiling rate (which remains unchanged by the legislation) with any related undercollection continuing to increase SDG&E's total undercollected costs.

The California Legislature continues to remain in emergency session to address the California energy crisis. Various legislative and other proposals that would significantly affect the structure of California's electric industry, the rates that SDG&E and other IOUs may charge their customers and the ability of the utilities to purchase electricity for their customers, and to finance and recover undercollected costs have been advanced. Among these proposals is that of the Governor that would, among other things, have the state of California purchase the IOUs' transmission systems for amounts at least equal to their net book value to provide the IOUs with funds to mitigate the situation. SDG&E has been having discussions with representatives of the governor concerning the possibility of such a transaction and what its terms might be. There is no assurance that these discussions will result in a sale of the transmission assets. SDG&E would consider entering into such a transaction only if the sales price and conditions of the sale and of future operating arrangements are reasonable.

Credit Ratings

Although the credit ratings of the company and SDG&E have not changed, California regulatory uncertainties have led the major credit-rating agencies to change their rating outlooks on most of the company's and SDG&E's securities to negative.

SDG&E Liquidity and Capital Resources

The rate ceiling has materially and adversely affected SDG&E's revenue collections and its related cash flows and liquidity. SDG&E has fully drawn upon substantially all of its short-term credit facilities. Its ability to access the capital markets and obtain additional financing has been substantially impaired by the financial distress being experienced by other California IOUs as well as by lender uncertainties concerning California utility regulation generally and the rapid growth of utility cost undercollections.

Continued purchases by the DWR for resale to SDG&E's customers of substantially all of the electricity that would otherwise be purchased by SDG&E or dramatic decreases in wholesale electricity prices, favorable action by the CPUC on SDG&E's electric-rate-surcharge application and SDG&E's access to the capital markets are required to manage and finance SDG&E's cost undercollections and provide adequate liquidity.

Effect On Other Subsidiaries

Other company subsidiaries have significant receivables from the other IOUs and from the PX/ISO. The collection of these receivables could be dependent on satisfactory resolution of the financial difficulties being experienced by those IOUs as a result of the California electric industry problem discussed above. In addition, the company's ability to fund its subsidiaries' capital expenditure program and liquidity requirements are significantly affected by the company's credit ratings and related ability to obtain financing on commercially reasonable terms. Also see "Natural Gas" below.

Natural Gas

Supply/demand imbalances are affecting the price of natural gas in California more than in the rest of the country because of California's dependence on natural gas fired electric generation due to air-quality considerations. The average price of natural gas at the California/Arizona (CA/AZ) border was $6.25/mmbtu in 2000, compared with $2.33/mmbtu in 1999. On December 11, 2000, the average spot cash gas price at the CA/AZ border reached a record high of $56.91/mmbtu. Underlying the high natural gas prices are several factors, including the increase in natural gas throughput for electric generation (a 40-percent increase in Southern California compared to 1999), colder winter weather and reduced natural gas supply resulting from historically low storage levels, lower natural gas production and a major pipeline rupture. In December 2000, SDG&E and SoCalGas filed separately with the FERC for a reinstitution of price caps on short-term interstate capacity to the CA/AZ border and between the interstate pipelines and California's local distribution companies, effective until March 31, 2001. The California utilities requested that, if the price of natural gas sold into California exceeds 150 percent of the national average, the price should be capped at that level, plus FERC-imposed transportation costs. The FERC responded by issuing extensive data requests, but has not otherwise acted on the requests.

On January 18, 2001, Pacific Gas and Electric Company (PG&E) filed an emergency application with the CPUC requesting that SoCalGas be ordered to purchase natural gas or supply available natural gas to meet PG&E's core procurement needs. Some of PG&E's suppliers are declining to sell natural gas to PG&E due to its poor credit rating. Although SoCalGas has agreed to supply a limited amount of natural gas to PG&E through March 31, 2001 (secured by PG&E customer receivables), it is still urging rejection of the request which, if approved, could severely jeopardize SoCalGas' ability to serve its own customers because of cash flow considerations.

Restructuring Of Electric Distribution

Thus far, the CPUC's electric industry restructuring has been confined to generation. Transmission and distribution have remained subject to traditional cost-of-service regulation. However, the CPUC is exploring the possibility of opening up electric distribution to competition. A CPUC staff report on this issue was submitted to the CPUC in July 2000, with dissenting opinions recommending against changing electric distribution regulation at this time due to the current state of electric industry restructuring. A proposed decision is expected in mid-2001.

Gas Industry Restructuring

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. In January 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's natural gas consumers.

In July 1999, after hearings, the CPUC issued a decision stating which natural gas regulatory changes it found most promising, encouraging parties to submit settlements addressing those changes, and providing for further hearings if necessary.

In October 1999, the state of California enacted a law (AB 1421) which requires that natural gas utilities provide "bundled basic gas service" (including transmission, storage, distribution, purchasing, revenue-cycle services and after-meter services) to all core customers, unless the customer chooses to purchase natural gas from a nonutility provider. The law prohibits the CPUC from unbundling most distribution-related natural gas services (including meter reading) and after-meter services (including leak investigation, inspecting customer piping and appliances, pilot relighting and carbon monoxide investigation) for core customers. The objective is to preserve both customer safety and customer choice.

Between late 1999 and April 2000, several conflicting settlement proposals were filed by various groups of parties that addressed the changes the CPUC found promising in July 1999. The principal issues in dispute included: whether firm, tradable rights to capacity on SoCalGas' major gas transmission lines should be created, with SoCalGas at risk for market demand for the recovery of the cost of these facilities; the extent to which SoCalGas' storage services should be further unbundled and SoCalGas be put at greater risk for recovery of storage costs; the manner in which interstate pipeline capacity held by SoCalGas to serve core markets should be allocated to core customers who purchase gas from energy service providers other than SoCalGas; and the recovery of the utilities' costs to implement whatever regulatory changes are adopted. Additional proposals included improving the access of energy service providers to sell natural gas supply to core customers of SoCalGas and SDG&E.

Certain parties contend that the restructuring process is an appropriate venue for addressing whether SoCalGas should refund retroactively to September 1999 the cost in rates of ownership and operation of one of SoCalGas' storage fields. SoCalGas actively opposes this proposal and the propriety of this venue for its resolution. In November 2000, these parties entered into a settlement with SoCalGas in a related CPUC proceeding that provides for no retroactive refund of the cost in rates of this field. This settlement is pending CPUC approval.

Hearings in the restructuring case were held in mid-2000 and a Proposed Decision (PD) was released in November 2000. A CPUC decision is expected in 2001. The PD does not recommend adoption of shareholder absorption of stranded interstate pipeline costs or retroactive refund of any amount related to the storage field. The PD recommends some, but not all, of the changes proposed by the California utilities. If adopted, the PD is not expected to have a negative earnings impact on the California utilities.

Performance-Based Regulation (PBR)

In recent years, the CPUC has directed utilities to use PBR. To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, PBR has replaced the general rate case and certain other regulatory proceedings for both SoCalGas and SDG&E. Under PBR, regulators generally require future income potential to be tied to achieving or exceeding specific performance and productivity measures, as well as cost reductions, rather than relying solely on expanding utility plant in a market where a utility already has a highly developed infrastructure.

The utilities' PBR mechanisms are in effect through December 31, 2002, at which time the mechanisms will be updated. That update will include, among other things, a reexamination of the companies' reasonable costs of operation in 2003 to be allowed in rates. Key elements of the current mechanisms include an annual indexing mechanism that adjusts rates by the inflation rate less a productivity factor and other adjustments to accommodate major unanticipated events, a sharing mechanism with customers that applies to earnings that exceed the authorized rate of return on rate base, rate refunds to customers if service quality deteriorates or awards if service quality exceeds set standards, and a change in authorized rate of return and customer rates if interest rates change by more than a specified amount. The SoCalGas rate change is triggered if the 12-month trailing average of actual market interest rates increases or decreases by more than 150 basis points and is forecasted to continue to vary by at least 150 basis points for the next year. The SDG&E rate change is triggered by a six-month trailing average and a 100-basis-point change in interest rates. If this occurs, there would be an automatic adjustment of rates for the change in the cost of capital according to a formula which applies a percentage of the change to various capital components.

Comprehensive Settlement Of Natural Gas Regulatory Issues

In July 1994, the CPUC approved a comprehensive settlement for SoCalGas (Comprehensive Settlement) of a number of regulatory issues, including rate recovery of a significant portion of the restructuring costs associated with certain long-term gas-supply contracts. In addition to the supply issues, the Comprehensive Settlement addressed the following other regulatory issues:

**Noncore revenues were governed by the Comprehensive Settlement through July 31, 1999. This treatment was replaced by the 1999 Biennial Cost Allocation Proceeding (BCAP), which went into effect on June 1, 2000. The CPUC's decision on the 1999 BCAP allows balancing account treatment for 75 percent of noncore revenues.

**The Gas Cost Incentive Mechanism (GCIM) for evaluating SoCalGas' natural gas purchases substantially replaced the previous process of reasonableness reviews. GCIM compares SoCalGas' cost of natural gas with a benchmark level, which is the average price of 30-day firm spot supplies in the basins in which SoCalGas purchases natural gas. 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 or savings outside the tolerance band are shared equally between customers and shareholders. The CPUC approved the use of natural gas futures for managing risk associated with the GCIM. SoCalGas enters into natural gas futures contracts in the open market on a limited basis to mitigate risk and better manage natural gas costs.

In 1998 the CPUC approved GCIM-related shareholder awards to SoCalGas totaling $13 million. On June 8, 2000, the CPUC approved an $8 million award for the year ended March 31, 1999, and deferred its decision regarding extending the GCIM beyond March 31, 2000 until an evaluation is performed by its staff. On January 4, 2001, the CPUC's Energy Division issued its evaluation report recommending the continuation of the GCIM with modifications. A CPUC decision is expected by September 2001.

In June 2000, SoCalGas filed its annual GCIM application with the CPUC, requesting an award of $10 million for the year ended March 31, 2000. On October 30, 2000, the CPUC's Office of Ratepayer Advocates recommended approval of the award and the extension of the GCIM beyond March 31, 2000, with certain modifications to the tolerance band and benchmark price. A CPUC decision is expected by September 2001.

Biennial Cost Allocation Proceeding

On November 4, 1999, the CPUC revised its previous decision on SoCalGas' 1996 BCAP, shifting $88 million of pipeline surcharges from the pipeline capacity relinquishments to noncore customers. The noncore customer rate impact of the decision is mitigated by overcollections in the regulatory accounts and is reflected in the rates adopted in the final 1999 BCAP decision.

On April 20, 2000, the CPUC issued a decision on the 1999 BCAP, adopting overall decreases in natural gas revenues of $210 million for SoCalGas and $37 million for SDG&E for transportation rates effective

June 1, 2000. For SoCalGas, there is a return to 75/25 (customer/shareholder) balancing account treatment for noncore transportation revenues, excluding certain transactions. In addition, unbundled noncore storage revenues are balanced 50/50 between customers and shareholders. Since the decreases reflect anticipated changes in corresponding costs, they have no effect on net income.

Cost Of Capital

For 2001, SoCalGas is authorized to earn a rate of return on common equity (ROE) of 11.6 percent and a 9.49 percent return on rate base (ROR), the same as in 2000 and 1999, unless interest-rate changes are large enough to trigger an automatic adjustment as discussed above under "Performance-Based Regulation." For SDG&E, electric industry restructuring has changed the method of calculating the utility's annual cost of capital. In June 1999, the CPUC adopted a 10.6 percent ROE and an 8.75 percent ROR for SDG&E's electric distribution and natural gas businesses. These rates remain in effect for 2000 and 2001. The electric-transmission cost of capital is determined under a separate FERC proceeding. SDG&E is required by its last cost of capital proceeding to file an application on or before May 8, 2001, proposing revisions to its authorized ROE, ROR and capital structure, to be in effect for 2002. The application will, among other things, consider the recent and ongoing financial impacts on SDG&E of electric industry restructuring.

Integration Of Core Gas Purchase Functions

On January 11, 2001, SoCalGas and SDG&E filed an application with the CPUC to integrate their natural gas purchasing departments. The filing calls for a single natural gas acquisition group to purchase natural gas for the two utilities' core gas customers by using their pooled gas portfolio assets. These assets include storage, interstate capacity and natural gas supply contracts. The two utilities would charge their core customers the same natural gas commodity rate from the diversified portfolio. The change would bring increased efficiency to the utilities' core gas purchase functions. The filing requests that this change be effective November 1, 2001. A CPUC decision is not expected until October 2001.

Note 15. SEGMENT INFORMATION

The company, primarily an energy services company, has three separately managed reportable segments comprised of SoCalGas, SDG&E and SET. The two utilities operate in essentially separate service territories under separate regulatory frameworks and rate structures set by the CPUC. SDG&E provides electric and natural gas service to San Diego and southern Orange counties. SoCalGas is a natural gas distribution utility, serving customers throughout most of Southern California and part of central California. SET is based in Stamford, Connecticut, and is engaged in wholesale trading and marketing of natural gas, power and petroleum in the United States, Canada, Europe and Asia. The accounting policies of the segments are the same as those described in Note 2, and segment performance is evaluated by management based on reported net income. Intersegment transactions generally are recorded the same as sales or transactions with third parties. Utility transactions are primarily based on rates set by the CPUC and FERC.

For the years ended December 31 (Dollars in millions)	2000	1999	1998
OPERATING REVENUES			
Southern California Gas	$2,854	$2,569	$2,427
San Diego Gas & Electric	2,671	2,207	2,249
Sempra Energy Trading	795	450	110
Intersegment revenues	(65)	(72)	(59)
All other	782	206	254
Total	$7,037	$5,360	$4,981
INTEREST REVENUE			
Southern California Gas	$ 27	$ 16	$ 4
San Diego Gas & Electric	51	40	31
Sempra Energy Trading	8	3	3
All other interest	(18)	(26)	2
Total interest	68	33	40
Sundry income (loss)	38	17	(25)
Total other income	$ 106	$ 50	$ 15

DEPRECIATION AND AMORTIZATION			
Southern California Gas	$ 263	$ 260	$ 254
San Diego Gas & Electric (See Note 14)	210	561	603
Sempra Energy Trading	32	29	25
All other	58	29	47
Total	$ 563	$ 879	$ 929
INTEREST EXPENSE			
Southern California Gas	$ 74	$ 60	$ 80
San Diego Gas & Electric	118	120	106
Sempra Energy Trading	18	15	5
All other	76	34	6
Total	$ 286	$ 229	$ 197
INCOME TAX EXPENSE (BENEFIT)			
Southern California Gas	$ 183	$ 182	$ 128
San Diego Gas & Electric	144	126	142
Sempra Energy Trading	63	(7)	(9)
All other	(120)	(122)	(123)
Total	$ 270	$ 179	$ 138
NET INCOME			
Southern California Gas	$ 206	$ 200	$ 158
San Diego Gas & Electric	145	193	185
Sempra Energy Trading	155	19	(13)
All other	(77)	(18)	(36)
Total	$ 429	$ 394	$ 294

At December 31 or for the years then ended (Dollars in millions)	2000	1999	1998
ASSETS			
Southern California Gas	$4,116	$ 3,452	$ 3,834
San Diego Gas & Electric	4,734	4,366	4,257
Sempra Energy Trading	4,689	1,981	1,400
All other	2,073	1,325	965
Total	$15,612	$11,124	$10,456
CAPITAL EXPENDITURES			
Southern California Gas	$ 198	$ 146	$ 128
San Diego Gas & Electric	324	245	227
Sempra Energy Trading	22	26	-
All other	215	172	83
Total	$ 759	$ 589	$ 438
GEOGRAPHIC INFORMATION			
Long-lived assets:			
United States	$ 6,080	$ 5,857	$ 5,849
Latin America	911	701	140
Canada	23	-	-
Total	$ 7,014	$ 6,558	$ 5,989
OPERATING REVENUES			
United States	$ 6,700	$ 5,280	$ 4,974
Latin America	154	16	7
Europe	158	62	-
Canada	14	2	-
Asia	11	-	-
Total	$ 7,037	$ 5,360	$ 4,981

Quarterly Financial Data (Unaudited)

Quarter ended (Dollars in millions except per-share amounts)	March 31	June 30	September 30	December 31
2000				

Revenues and other income	$1,460	$ 1,530	$ 1,832	$2,321
Operating expenses	1,206	1,295	1,605	2,053
Income before interest and income taxes	$ 254	$ 235	$ 227	$ 268
Net income	$113	$ 110	$ 110	$ 95
Average common shares outstanding (diluted)	228.4	201.5	201.5	202.7
Net income per common share (diluted)	$ 0.49	$ 0.55	$ 0.55	$ 0.47
1999				
Revenues and other income	$1,186	$1,512	$ 1,246	$1,466
Operating expenses	966	1,375	998	1,269
Income before interest and income taxes	$ 220	$ 137	$ 248	$ 197
Net income	$ 99	$ 82	$ 108	$ 105
Average common shares outstanding (diluted)	237.4	237.5	237.8	237.6
Net income per common share (diluted)	$ 0.42	$0.35	$ 0.45	$0.44

The sum of the quarterly amounts does not equal the annual total due to rounding. Reclassifications have been made to certain of the amounts since they were presented in the Quarterly Reports on Form 10-Q.

QUARTERLY COMMON STOCK DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2000				
Market price				
High	$19 1/4	$19 1/4	$21	$24 7/8
Low	16 1/4	16 3/16	17	19 3/8
Dividends				
Declared	$0.25	$0.25	$0.25	$0.25
1999				
Market price				
High	$26	$24 7/8	$23 3/16	$21 3/4
Low	19 1/8	18 1/2	20	17 1/8
Dividends				
Declared	$0.39	$0.39	$0.39	$0.39

EXHIBIT 21.01

SEMPRA ENERGY
Schedule of Significant Subsidiaries at December 31, 2000

Subsidiary	State of Incorporation or Other Jurisdiction
Chilquinta Energia, S.A.	Chile
Luz del Sur, S.A.A.	Peru
San Diego Gas & Electric Company	California
Sempra Energy Financial	California
Sempra Energy Global Enterprises	California
Sempra Energy International	California
Sempra Energy Resources	California
Sempra Energy Services	Texas
Sempra Energy Trading Corp.	Delaware
Southern California Gas Company	California