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, 2004

OR

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

SAN DIEGO GAS & ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

| CALIFORNIA | 1-3779 | 95-1184800 |
|---|---|---|
| (State of incorporation or organization) | (Commission File Number) | (I.R.S. Employer Identification No. |

| 8326 CENTURY PARK COURT, SAN DIEGO, CALIFORNIA | 92123 |
|---|---|
| (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 |
|---|---|
| Preference Stock (Cumulative) Without Par Value (except $1.70 and $1.7625 Series) | American |
| Cumulative Preferred Stock, $20 Par Value (except 4.60% Series) | |

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days.

Yes [ X ] No [ ]

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [ X ]

Exhibit Index on page 90. Glossary on page 96.

Aggregate market value of the voting preferred stock held by non-affiliates of the registrant as of January 31, 2005 was $23.7 million.

Registrant's common stock outstanding as of January 31, 2005 was wholly owned by Enova Corporation.

DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the Information Statement prepared for the May 2005 annual meeting of shareholders are incorporated by reference into Part III.

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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. The words "estimates," "believes," "expects," "anticipates," "plans," "intends," "may," "could," "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 and national economic, competitive, political, legislative and regulatory conditions and developments; actions by the California Public Utilities Commission, the California State Legislature, the California Department of Water Resources, and the Federal Energy Regulatory Commission and other regulatory bodies in the United States; capital markets conditions, inflation rates, interest rates and exchange rates; energy and trading markets, including the timing and extent of changes in commodity prices; the availability of natural gas; weather conditions and conservation efforts; war and terrorist attacks; business, regulatory, environmental and legal decisions and requirements; the status 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 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 San Diego Gas & Electric (SDG&E or the company) is given in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

SDG&E's common stock is wholly owned by Enova Corporation, which is a wholly owned subsidiary of Sempra Energy, a California-based Fortune 500 holding company. The financial statements herein are the Consolidated Financial Statements of SDG&E and its sole subsidiary, SDG&E Funding LLC. Sempra Energy also indirectly owns the common stock of Southern California Gas Company (SoCalGas). SDG&E and SoCalGas are collectively referred to herein as "the California Utilities."

**Company Website**

The company's website address is http://www.sdge.com/ and Sempra Energy’s website address is http://www.sempra.com/investor.htm. The company makes available free of charge via a hyperlink on its website its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission.

**RISK FACTORS**

*The following risk factors and all other information contained in this report should be considered carefully when evaluating SDG&E. These risk factors could affect the actual results of SDG&E and cause such results to differ materially from those expressed in any forward-looking statements of, or made by or on behalf of, SDG&E. Other risks and uncertainties, in addition to those that are described below, may also impair its business operations. If any of the following risks occurs, SDG&E's business, cash flows, results of operations and financial condition could be seriously harmed. These risk factors should be read in conjunction with the other detailed information concerning SDG&E set forth in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.*

***SDG&E is subject to extensive regulation by state, federal and local legislation and regulatory authorities, which may adversely affect the operations, performance and growth of its business.***

The California Public Utilities Commission (CPUC), which consists of five commissioners appointed by the Governor of California for staggered six-year terms, regulates SDG&E's rates (except electric transmission rates, which are regulated by the Federal Energy Regulatory Commission (FERC)) and conditions of service, sales of securities, rates of return, rates of depreciation, uniform systems of accounts, examination of records and long-term resource procurement. The CPUC conducts various reviews of utility performance (including reasonableness and prudency reviews) and affiliate relationships and conducts audits and investigations into various matters which may, from time to time, result in disallowances and penalties adversely affecting earnings and cash flows. Various proceedings involving the CPUC and relating to SDG&E's rates, costs, incentive mechanisms, performance-based regulation and compliance with affiliate and holding company rules are discussed in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

Periodically, SDG&E's rates are approved by the CPUC based on forecasts of capital and operating costs. If SDG&E's actual capital and operating costs were to exceed the amount included in its base rates approved by the CPUC, it would adversely affect earnings and cash flows.

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC adopted Performance-Based Regulation (PBR) for the California Utilities. Under PBR, regulators require future income potential to be tied to achieving or exceeding specific performance and productivity goals, rather than relying solely on expanding utility plant to increase earnings. The three areas that are eligible for PBR rewards are: operational incentives based on measurements of safety, reliability and customer satisfaction; energy efficiency rewards based on the effectiveness of the programs; and natural gas procurement rewards. Although SDG&E has received significant PBR rewards in the past, there can be no assurance that SDG&E will receive rewards at similar levels in the future, or at all. Additionally, if SDG&E fails to achieve certain minimum performance levels established under the PBR mechanisms, it may be assessed financial disallowances or penalties which could adversely affect their earnings and cash flows.

The FERC regulates electric transmission rates, the transmission and wholesale sales of electricity in interstate commerce, transmission access and other similar matters involving SDG&E.

SDG&E may be impacted by new regulations, decisions, orders or interpretations of the CPUC, FERC or other regulatory bodies. New legislation, regulations, decisions, orders or interpretations could change how SDG&E operates, could affect its ability to recover their various costs through rates or adjustment mechanisms, or could require SDG&E to incur additional expenses.

***SDG&E may incur substantial costs and liabilities as a result of its ownership of nuclear facilities.***

SDG&E owns a 20% interest in the San Onofre Nuclear Generating Station (SONGS), a 2,150 megawatt nuclear generating facility near San Clemente, California. The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. SDG&E's ownership interest in SONGS subjects it to the risks of nuclear generation, which include:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

***The California Utilities' future results of operations and financial condition may be materially adversely affected by the outcome of pending litigation against them.***

The California energy crisis of 2000 and 2001 has generated numerous lawsuits, governmental investigations and regulatory proceedings involving many energy companies, including Sempra Energy and the California Utilities. They are the remaining defendants in class action and individual antitrust and unfair competition lawsuits scheduled for a jury trial to begin in September 2005 in which the plaintiffs have asserted that they are entitled to recover $24 billion in damages. Additional lawsuits have been filed by the Attorney General of Nevada and by others. They are also responding to an ongoing investigation being conducted by the California Attorney General and an ongoing CPUC proceeding related to the increase in natural gas prices at the California-Arizona border in 2000-2001. The California Utilities have expended and continue to expend substantial amounts defending these lawsuits and in connection with related investigations and regulatory proceedings. If these matters are ultimately resolved unfavorably to the California Utilities, their results of operations and financial condition and those of Sempra Energy may be materially adversely affected.

These proceedings are discussed in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

***SDG&E's cash flows, ability to pay dividends and ability to meet its debt obligations largely depend on the performance of its utility operations.***

SDG&E's utility operations are its major source of liquidity. SDG&E's cash flows, ability to meet its obligations to creditors and its ability to pay dividends on its common stock are largely dependent upon the sufficiency of utility earnings and cash flows in excess of utility needs.

***Natural disasters, catastrophic accidents or acts of terrorism could materially adversely affect SDG&E's business, earnings and cash flows.***

Like other major industrial facilities, SDG&E's SONGS nuclear facility, electric transmission facilities, and natural gas pipelines and storage facilities may be damaged by natural disasters, catastrophic accidents or acts of terrorism. Any such incidents could result in severe business disruptions, significant decreases in revenues or significant additional costs to the company, which could have a material adverse effect on SDG&E's earnings and cash flows. Given the nature and location of these facilities, any such incidents also could cause fires, leaks, explosions, spills or other significant damage to natural resources or property belonging to third parties, or personal injuries, which could lead to significant claims against the company. Insurance coverage may become unavailable for certain of these risks and the insurance proceeds received for any loss of or damage to any of its facilities, or for any loss of or damage to natural resources or property or personal injuries caused by its operations, may be insufficient to cover the company's losses or liabilities without materially adversely affecting the company's financial condition, earnings and cash flows.

## GOVERNMENT REGULATION

### California Utility Regulation

The CPUC, which consists of five commissioners appointed by the Governor of California for staggered six-year terms, regulates SDG&E's 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 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 CPUC also regulates the relationship of utilities with their holding companies and is currently conducting an investigation into this relationship. This investigation is discussed further in Note 11 of the notes to Consolidated Financial Statements herein.

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.

The CEC conducts a 20-year forecast of supply availability and prices for every market sector consuming natural gas in California. This forecast includes resource evaluation, pipeline capacity needs, natural gas demand and wellhead prices, and costs of transportation and distribution. This analysis is used to support long-term investment decisions.

### United States Utility Regulation

The 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. Both the FERC and the CPUC are currently investigating prices charged to the California investor-owned utilities (IOUs) by various suppliers of natural gas and electricity. Further discussion is provided in Notes 10 and 11 of the notes to Consolidated Financial Statements herein.

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.

## Local Regulation

SDG&E has electric franchises with the two counties and the 26 cities in its electric service territory, and natural gas franchises with the one county and the 18 cities in its natural gas service territory. These franchises allow SDG&E to locate, operate and maintain facilities for the transmission and distribution of electricity and/or natural gas in streets and other public places. The franchises do not have fixed terms, except for the electric and natural gas franchises with the cities of Encinitas (2012), San Diego (2021), Coronado (2028) and Chula Vista (2014), and the natural gas franchises with the city of Escondido (2036) and the county of San Diego (2030).

## Licenses and Permits

SDG&E obtains numerous permits, authorizations and licenses in connection with the transmission and distribution of natural gas and electricity. They require periodic renewal, which results in continuing regulation by the granting agency.

Other regulatory matters are described in Notes 10 and 11 of the notes to Consolidated Financial Statements herein.

## ELECTRIC UTILITY OPERATIONS

## Customers

At December 31, 2004 the company had 1.3 million meters consisting of 1,170,000 residential, 139,000 commercial, 460 industrial, 1,940 street and highway lighting, and 7,700 direct access. The company's service area covers 4,100 square miles. The company added 22,000 new electric customer meters in 2004 and 18,000 in 2003, representing growth rates of 1.7% and 1.4% respectively.

## Resource Planning and Power Procurement

SDG&E's resource planning, power procurement and related regulatory matters are discussed below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 10, 11 and 12 herein.

## Electric Resources

Based on CPUC-approved purchased-power contracts currently in place with SDG&E's various suppliers and SDG&E's 20-percent share of a generating plant, as of December 31, 2004, the supply of electric power available to SDG&E is as follows:

<table>
<caption>

| Supplier | Source | Expiration date | Megawatts (MW) |
|---|---|---|---|
| Generation: SONGS | | | 430 |
| Purchased power contracts: | | | |
| <s> | <c> | <c> | <c> |
| Long-term contracts: | | | |
| Portland General Electric(PGE) | Coal | December 2013 | 88 |
| DWR-allocated contracts: | | | |
| Williams Energy Marketing & Trading | Natural gas | December 2010 | 1,885 |
| Sunrise Power Co. LLC | Natural gas | June 2012 | 572 |
| Other | Natural gas/wind | 2005 to 2013 | 290 |
| Total | | | 2,747 |
| Other contracts with Qualifying Facilities (QFs): | | | |
| Applied Energy Inc. | Cogeneration | November 2019 | 107 |
| Yuma Cogeneration | Cogeneration | May 2024 | 57 |
| Goal Line Limited Partnership | Cogeneration | February 2025 | 50 |
| Other (73 contracts) | Cogeneration | Various | 16 |
| Total | | | 230 |
| Other contracts with renewable sources: | | | |
| Oasis Power Partners | Wind | December 2019 | 60 |
| AES Delano | Bio-mass | December 2007 | 49 |
| PPM Energy | Wind | December 2018 | 25 |
| WTE/FPL | Wind | February 2019 | 17 |
| Other (6 contracts) | Bio-gas | 4-14 year terms | 24 |
| Total | | | 175 |
| Total generation and contracted | | | 3,670 |

</table>

Under the contract with PGE, SDG&E pays a capacity charge plus a charge based on the amount of energy received and/or PGE's non-fuel costs. Costs under the contracts with QFs are based on SDG&E's avoided cost. Charges under the remaining contracts are for firm and as-available energy 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.

**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 it down. Decommissioning of Unit 1 is now in progress and its spent nuclear fuel is being stored on site.

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.

SDG&E had fully recovered its SONGS capital investment through December 31, 2003.

Additional information concerning the SONGS units and nuclear decommissioning is provided below and in "Environmental Matters" herein, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 4, 10 and 12 of the notes to Consolidated Financial Statements herein.

**Nuclear Fuel Supply**

The nuclear-fuel cycle includes services performed by others under various contracts through 2008, including mining and milling of uranium concentrate, conversion of uranium concentrate to uranium hexafluoride, enrichment services, and fabrication of fuel assemblies.

Spent fuel from SONGS is being stored on site, where storage capacity is expected to be adequate at least 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 approximately $1.00 per megawatt-hour of net nuclear generation, or $3 million per year. The DOE projects that it will not begin accepting spent fuel until 2010 at the earliest.

To the extent not currently provided by the contracts, 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 and the storage and movement of spent fuel is provided in Notes 10 and 12, respectively, of the notes to Consolidated Financial Statements herein.

**Power Pools**

SDG&E is a participant in the Western Systems Power Pool, which includes an electric-power and transmission-rate agreement with utilities and power agencies located throughout the United States and Canada. More than 280 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 the FERC.

**Transmission Arrangements**

The Pacific 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 Pacific Intertie is 266 MW.

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's Baja California Norte system is connected to SDG&E's system via two 230-kilovolt interconnections with firm capability of 408 MW in the north to south direction and 800 MW in the south to north direction.

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

**Transmission Access**

The FERC has established rules to implement the transmission-access provisions of the National Energy Policy Act of 1992. These rules specify procedures for others' requests for transmission service. The FERC approved the California IOUs' transfer of operation and control of their transmission facilities to the ISO in 1998. Additional information regarding the FERC, ISO and transmission issues are provided in Note 11 of the notes to Consolidated Financial Statements herein.

**NATURAL GAS UTILITY OPERATIONS**

**Resource Planning and Natural Gas Procurement and Transportation**

SDG&E is engaged in the purchase and distribution of natural gas. The company's resource planning, power procurement, contractual commitments and related regulatory matters are discussed below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 11 and 12 of the notes to Consolidated Financial Statements herein.

**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 electric generation, wholesale, large commercial and industrial customers.

Most core customers purchase natural gas directly from the company. Core customers are permitted to aggregate their natural gas requirements and purchase directly from brokers or producers. SDG&E continues to be obligated to purchase reliable supplies of natural gas to serve the requirements of the core customers.

**Natural Gas Procurement and Transportation**

Most of the natural gas purchased and delivered by SDG&E is produced outside of California, primarily in the southwestern U.S. and Canada. SDG&E purchases natural gas under short-term contracts. Short-term purchases are primarily based on monthly spot-market prices.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines that expire on various dates between 2005 and 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues its ongoing assessment of its pipeline capacity portfolio, including the release of a portion of this capacity to third parties. In accordance with regulatory directives, SDG&E will reconfigure its pipeline capacity portfolio by November 2005 to secure firm transportation rights from a diverse mix of U.S. and Canadian supply sources for its projected core customer natural gas requirements. All of SDG&E's natural gas is delivered through SoCalGas' pipelines under a short-term transportation agreement. In addition, under a separate agreement expiring in March 2006, SoCalGas provides SDG&E eight billion cubic feet of storage capacity.

According to "Btu's Daily Gas Wire", the annual average spot price of natural gas at the California/Arizona border was $5.53 per million British thermal unit (mmbtu) in 2004 ($6.35 per mmbtu in December 2004), compared with $5.10 per mmbtu in 2003 and $3.14 per mmbtu in 2002. Prices for natural gas increased toward the end of 2002, 2003 and in 2004. The company's weighted average cost (including transportation charges) per mmbtu of natural gas was $6.11 in 2004, $5.14 in 2003 and $3.76 in 2002.

With improved delivery capacity to California, the company expects adequate resources to be available at prices that generally will follow national natural gas pricing trends and volatility.

**Demand for Natural Gas**

SDG&E faces competition in the residential and commercial customer markets based on the customers' preferences for natural gas compared with other energy products. The demand for natural gas by electric generators is influenced by a number of factors. In the short-term, natural gas use by electric generators is impacted by the availability of alternative sources of generation. The availability of hydroelectricity is highly dependent on precipitation in the western United States. In addition, natural gas use is impacted by the performance of other generation sources in the western United States, including nuclear and coal, and other natural gas facilities outside the service area. Natural gas use is also impacted by changes in end-use electricity demand. For example, natural gas use generally increases during summer heat waves. Over the long-term, natural gas use will be greatly influenced by additional factors such as the location of new power plant construction. More generation capacity currently is being constructed outside SDG&E's service area than within it. This new generation will likely displace the output of older, less efficient local generation, reducing use of natural gas for local electric generation.

Effective March 31, 1998, electric industry restructuring provided out-of-state producers the option to purchase energy for California utility customers. 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 SDG&E natural gas operations, future volumes of natural gas transported for electric generating plant customers may be significantly affected to the extent that regulatory changes divert electric generation from SDG&E’s service area.

Growth in the natural gas markets is largely dependent upon the health and expansion of the Southern California economy and prices of other energy products. 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 company added 12,000 and 11,000 natural gas new customer meters in 2004 and 2003, respectively, representing growth rates of 1.5 percent and 1.4 percent, respectively. The company expects that its growth rate for 2005 will approximate that for 2004.

In the interruptible industrial market, customers are capable of burning a fuel other than natural gas. Fuel oil is the most significant competing energy alternative. The company's ability to maintain its industrial market share is largely dependent on price. The relationship between natural gas supply and demand has the greatest impact on the price of the company's product. With the reduction of natural gas production from domestic sources, the cost of natural gas from non-domestic sources may play a greater role in the company's competitive position in the future. The price of oil depends upon a number of factors, including the relationship between worldwide supply and demand, and the policies of foreign and domestic governments.

The natural gas distribution business is seasonal in nature as variations in weather conditions generally result in greater revenues during the winter months when temperatures are colder. As is prevalent in the industry, the company injects natural gas into storage during the summer months (usually April through October) for withdrawal from storage during the winter months (usually November through March) when customer demand is higher.

**RATES AND REGULATION**

Information concerning rates and regulations applicable to the company is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 1, 10 and 11 of the notes to Consolidated Financial Statements herein.

**ENVIRONMENTAL MATTERS**

Discussions about environmental issues affecting the company are included in Note 12 of the notes to Consolidated Financial Statements herein. 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, allowing California's IOUs to recover their hazardous waste cleanup costs, including those related to Superfund sites or similar sites requiring cleanup. Cleanup costs at sites related to electric generation were specifically excluded from the collaborative by the CPUC. Recovery of 90 percent of hazardous waste 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.

During the early 1900s, SDG&E and its predecessors manufactured gas from coal or oil. The manufactured-gas plants (MGPs) often have become contaminated with the hazardous residual by-products of the process. SDG&E identified three former MGPs, two of which were remediated in 1998 and 2000, with closure letters being received. The estimated remaining remediation liability on the third site is $1.8 million.

SDG&E sold its fossil-fuel generating facilities in 1999. As a part of its due diligence for the sale, SDG&E conducted a thorough environmental assessment of the facilities. Pursuant to the sale agreements for such facilities, SDG&E and the buyers have apportioned responsibility for such environmental conditions generally based on contamination existing at the time of transfer and the cleanup level necessary for the continued use of the sites as industrial sites. While the sites are relatively clean, the assessments identified some instances of significant contamination, principally resulting from hydrocarbon releases, for which SDG&E has a cleanup obligation under the agreement. Estimated costs to perform the necessary remediation are $11 million. These costs were offset against the sales price for the facilities, together with other appropriate costs, and the remaining net proceeds were included in the calculation of customer rates. Remediation of the plants commenced in early 2001. During 2002, cleanup was completed at several minor sites at a cost of $0.4 million. In late 2002, additional assessments were started at the primary sites, where cleanup commenced in 2003 and is expected to be completed during 2005. In 2003, cleanup was completed at the Encina power plant site at a cost of $0.8 million. In 2004, cleanup was completed at two combustion turbine sites at a cost of $0.7 million.

SDG&E lawfully disposes 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 10 other entities have been named potentially responsible parties (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 percent, subject to adjustment based on allocations of responsibility. The total estimate for all PRPs is $1 million for the development of the cleanup plan and $2 million to $8 million for the actual cleanup. Since inception, SDG&E's share of the cleanup expenses and plan development was $0.2 million. Cleanup is expected to commence in 2005.

At December 31, 2004, the company's estimated remaining investigation and remediation liability related to hazardous waste sites, including the MGPs, was $2.7 million, of which 90 percent is authorized to be recovered through the Hazardous Waste Collaborative mechanism. This estimated cost excludes remediation costs associated with SDG&E's former fossil-fuel power plants. 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 exposure to the type of EMFs emitted by power lines and other electrical facilities and adverse health effects. 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 the proximity of homes to certain power lines and equipment and childhood leukemia. 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 IOUs 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. During 2004, the CPUC instituted a rulemaking to re-examine its policies related to EMFs and determine whether the current mitigation policies and utility directives should be updated in light of science that has developed over the last decade.

**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 generating facilities, the company's primary air-quality issue, compliance with these standards now 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 previously 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 kelp 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 $34 million. These mitigation projects are expected to be completed in 2008. Through December 31, 2003, SONGS mitigation costs were recovered through the ICIP mechanism. SONGS mitigation costs incurred after December 31, 2003, are being capitalized and recovered from ratepayers over the remaining life of the SONGS units, subject to CPUC approval in the Edison rate case. Additional information on SONGS cost recovery is provided in Note 10 of the notes to Consolidated Financial Statements herein.

**OTHER MATTERS**

**Research, Development and Demonstration (RD&D)**

For 2004, the CPUC authorized SDG&E to fund $1.2 million and $5.7 million for its natural gas and electric RD&D programs, respectively, including $5.7 million to the CEC for its PIER (Public Interest Energy

Research) Program. SDG&E's annual RD&D costs have averaged $6.5 million over the past three years.

**Employees of Registrant**

As of December 31, 2004, the company had 4,405 employees, compared to 4,441 at December 31, 2003.

**Labor Relations**

Certain employees at SDG&E are represented by the Local 465 International Brotherhood of Electrical Workers. The current contract is in effect through August 31, 2008.

## ITEM 2. PROPERTIES

**Electric Properties**

SDG&E's interest in SONGS is described in "Electric Resources" herein. At December 31, 2004, SDG&E's electric transmission and distribution facilities included substations, and overhead and underground lines. The electric facilities are located in San Diego, Imperial and Orange counties and in Arizona, and consist of 1,814 miles of transmission lines and 21,433 miles of distribution lines. Periodically, various areas of the service territory require expansion to accommodate customer growth.

**Natural Gas Properties**

At December 31, 2004, SDG&E's natural gas facilities, which are located in San Diego and Riverside counties, consisted of the Moreno and Rainbow compressor stations, 166 miles of high pressure transmission pipelines, 7,969 miles of high and low pressure distribution mains, and 6,155 miles of service lines.

**Other Properties**

SDG&E occupies an office complex 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 its business.

## ITEM 3. LEGAL PROCEEDINGS

SDG&E and the County of San Diego are continuing to negotiate the remaining terms of a settlement relating to alleged environmental law violations by SDG&E and its contractors in connection with the abatement of asbestos-containing materials during the demolition of a natural gas storage facility in 2001. SDG&E expects that any settlement with the County would involve payments by SDG&E of less than $750,000. In January 2005, Sempra Energy and SDG&E received a grand jury subpoena from the United States Attorney's Office in San Diego seeking documents related to this matter. The companies are fully cooperating with the investigation.

Except for the matters described above and in Note 12 of the notes to Consolidated Financial Statements or referred to elsewhere in this Annual Report, neither the company nor its subsidiary is 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**

All of the issued and outstanding common stock of SDG&E is owned by Enova Corporation, a wholly owned subsidiary of Sempra Energy. The information required by Item 5 concerning dividends declared is included in the "Statements of Consolidated Changes in Shareholders' Equity" set forth in Item 8 of this Annual Report herein.

**ITEM 6. SELECTED FINANCIAL DATA**

<table>
<caption>

| (Dollars in millions) | At December 31, or for the years then ended | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| <s> | <c> | <c> | <c> | <c> | <c> |
| Income Statement Data: | | | | | |
| Operating revenues | $ 2,274 | $ 2,311 | $ 1,725 | $ 2,362 | $ 2,671 |
| Operating income | $ 251 | $ 381 | $ 262 | $ 221 | $ 235 |
| Dividends on preferred stock | $ 5 | $ 6 | $ 6 | $ 6 | $ 6 |
| Earnings applicable to common shares | $ 208 | $ 334 | $ 203 | $ 177 | $ 145 |
| Balance Sheet Data: | | | | | |
| Total assets | $ 6,834 | $ 6,461 | $ 6,285 | $ 6,542 | $ 5,843 |
| Long-term debt | $ 1,022 | $ 1,087 | $ 1,153 | $ 1,229 | $ 1,281 |
| Short-term debt (a) | $ 66 | $ 66 | $ 66 | $ 93 | $ 66 |
| Preferred stock subject to mandatory redemption (b) | $ -- | $ -- | $ 25 | $ 25 | $ 25 |
| Shareholders' equity | $ 1,376 | $ 1,343 | $ 1,223 | $ 1,165 | $ 1,138 |

(a) Includes long-term debt due within one year.
(b) At December 31, 2004 and 2003, $19 million and $21 million, respectively, were included in Deferred Credits and Other Liabilities, and $2 million and $3 million, respectively, were included in Other Current Liabilities on the Consolidated Balance Sheets.
</table>

Since SDG&E is a wholly owned subsidiary of Enova Corporation, per share data is not provided.

This data should be read in conjunction with the Consolidated Financial Statements and the notes to Consolidated Financial Statements contained herein.

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

**INTRODUCTION**

This section of the 2004 Annual Report includes management's discussion and analysis of operating results from 2002 through 2004, and provides information about the capital resources, liquidity and financial performance of SDG&E. This section also focuses on the major factors expected to influence future operating results and discusses investment and financing activities and plans. It should be read in conjunction with the Consolidated Financial Statements included in this Annual Report.

The company is an operating public utility engaged in the electric and natural gas businesses, servicing 3.3 million consumers. It distributes electric energy, purchased from others or generated from its 20 percent interest in a nuclear facility, through 1.3 million electric meters in San Diego County and an adjacent portion of southern Orange County, California. It also purchases and distributes natural gas through 800,000 meters in San Diego County and transports electricity and natural gas for others. SDG&E's service area encompasses 4,100 square miles. SDG&E's only subsidiary is SDG&E Funding LLC, which was formed to facilitate the issuance of SDG&E's rate reduction bonds described in Note 3 of the notes to Consolidated Financial Statements. SDG&E is a substantially wholly owned indirect subsidiary of Sempra Energy. SDG&E and its sister utility, Southern California Gas Company (SoCalGas), which distributes natural gas throughout most of Southern California and a portion of central California, are collectively referred to herein as "the California Utilities."

**RESULTS OF OPERATIONS**

The following table shows net income for each of the last five years.

(Dollars in millions)

| | |
|---|---|
| 2004 | $ 213 |
| 2003 | $ 340 |
| 2002 | $ 209 |
| 2001 | $ 183 |
| 2000 | $ 151 |

To understand the operations and financial results of the company, it is important to understand the ratemaking procedures to which the company is subject.

The company is subject to various regulatory bodies and rules at national, state and local levels. The primary regulatory body is the California Public Utilities Commission (CPUC), which regulates utility rates and operations. The Federal Energy Regulatory Commission (FERC) regulates interstate transportation of natural gas and electricity and various related matters. The Nuclear Regulatory Commission regulates nuclear generating plants. Municipalities and other local authorities regulate the location of utility assets, including natural gas pipelines and electric lines.

California's electric utility industry was significantly affected by California's restructuring of the industry during 2000-2001. Beginning in mid-2000 and continuing into 2001, supply/demand imbalances and a number of other factors resulted in abnormally high electric commodity costs, leading to several legislative and regulatory responses, including a ceiling imposed on the cost of the electric commodity that SDG&E could pass on to its small-usage customers. To obtain adequate supplies of electricity, beginning in February 2001 and continuing through December 31, 2002, the DWR began purchasing power to fulfill the full net short position of the investor-owned utilities (IOUs), consisting of all electricity requirements of the IOUs’ customers other than that provided by their existing generating facilities or their previously existing purchased-power contracts.

In 2003, the CPUC established the allocation of the power purchased by the DWR under long-term contracts for the IOUs' customers and the related cost responsibility among the IOUs for that power. In addition, the IOU's resumed their electric commodity procurement function for power requirements in excess of that provided by the DWR's contracts allocated to them. This is discussed further in Note 10 of the notes to Consolidated Financial Statements and under "Factors Influencing Future Performance."

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. Further restructuring continues to be considered, as discussed in Note 11 of the notes to Consolidated Financial Statements.

***Electric Revenue and Cost of Electric Fuel and Purchased Power.*** Electric revenues decreased to $1,678 million in 2004 from $1,802 million in 2003, and the cost of electric fuel and purchased power increased to $0.6 billion in 2004 from $0.5 billion in 2003. The decrease in revenues was due to more power being provided to SDG&E's customers by the DWR in 2004 as discussed in Note 10 of the notes to Consolidated Financial Statements, offset partially by higher electric commodity costs. Additionally, 2003 revenue included the recognition of $116 million related to the approved settlement of intermediate-term purchase power contracts in the third quarter of 2003 and higher earnings from Performance-Based Regulation (PBR) awards. Performance awards are discussed in Note 11 of the notes to Consolidated Financial Statements. The increased costs were primarily attributable to the higher electric commodity costs and higher volumes, offset partially by the increased power being provided by the DWR.

Electric revenues increased to $1.8 billion in 2003 from $1.3 billion in 2002, and the cost of electric fuel and purchased power increased to $0.5 billion in 2003 from $0.3 billion in 2002. The changes were attributable to several factors, including the effect of the DWR's purchasing the net short position of SDG&E during 2002, and higher electric commodity costs and volumes. In addition, the increase in revenue was due to the settlement of the intermediate-term purchase power contracts and higher PBR awards in 2003 and the increase in authorized distribution revenue.

***Natural Gas Revenue and Cost of Natural Gas.*** Natural gas revenues increased to $596 million in 2004 from $509 million in 2003, and the cost of natural gas increased to $347 million in 2004 from $274 million in 2003. The increases were primarily attributable to natural gas cost increases, which are passed on to customers.

Under the current regulatory framework, the cost of natural gas purchased for customers and the variations in that cost are passed through to the customers on a substantially concurrent basis. However, SDG&E's natural gas procurement PBR mechanism provides an incentive mechanism by measuring SDG&E's procurement of natural gas against a benchmark price comprised of monthly natural gas indices, resulting in shareholder rewards for costs achieved below the benchmark and shareholder penalties when costs exceed the benchmark. Further discussion is provided in Notes 1 and 11 of the notes to Consolidated Financial Statements.

Natural gas revenues increased to $509 million in 2003 from $431 million in 2002, and the cost of natural gas increased to $274 million in 2003 from $205 million in 2002. The change was primarily attributable to natural gas price increases, partially offset by reduced volumes.

The tables below summarize the components of electric and natural gas volumes and revenues by customer class for the years ended December 31, 2004, 2003 and 2002.

<table>
ELECTRIC TRANSMISSION AND DISTRIBUTION
(Dollars in millions, volumes in million kilowatt hours)
<caption>

| | 2004 | | 2003 | | 2002 | |
|---|---|---|---|---|---|---|
| | Volumes | Revenue | Volumes | Revenue | Volumes | Revenue |
| <s> | <c> | <c> | <c> | <c> | <c> | <c> |
| Residential | 7,038 | $ 692 | 6,702 | $ 731 | 6,266 | $ 649 |
| Commercial | 6,592 | 644 | 6,263 | 674 | 6,053 | 633 |
| Industrial | 2,084 | 134 | 1,987 | 162 | 1,893 | 161 |
| Direct access | 3,441 | 105 | 3,322 | 87 | 3,448 | 117 |
| Street and highway lighting | 97 | 11 | 91 | 11 | 88 | 9 |
| Off-system sales | - | - | 8 | - | 5 | -- |
| | 19,252 | 1,586 | 18,373 | 1,665 | 17,753 | 1,569 |
| Balancing accounts and other | | 92 | | 137 | | (275) |
| Total | | $ 1,678 | | $ 1,802 | | $ 1,294 |

</table>

<table>
NATURAL GAS SALES, TRANSPORTATION & EXCHANGE
(Dollars in millions, volumes in billion cubic feet)
<caption>

| | Natural Gas Sales | | Transportation & Exchange | | Total | |
|---|---|---|---|---|---|---|
| | Volumes | Revenue | Volumes | Revenue | Volumes | Revenue |
| <s> | <c> | <c> | <c> | <c> | <c> | <c> |
| 2004: | | | | | | |
| Residential | 33 | $ 332 | -- | $ -- | 33 | $ 332 |
| Commercial and industrial | 18 | 142 | 4 | 4 | 22 | 146 |
| Electric generation plants | - | 2 | 74 | 36 | 74 | 38 |
| | 51 | $ 476 | 78 | $ 40 | 129 | 516 |
| Balancing accounts and other | | | | | | 80 |
| Total | | | | | | $ 596 |
| 2003: | | | | | | |
| Residential | 32 | $ 291 | -- | $ -- | 32 | $ 291 |
| Commercial and industrial | 17 | 127 | 4 | 5 | 21 | 132 |
| Electric generation plants | - | 3 | 62 | 30 | 62 | 33 |
| | 49 | $ 421 | 66 | $ 35 | 115 | 456 |
| Balancing accounts and other | | | | | | 53 |
| Total | | | | | | $ 509 |
| 2002: | | | | | | |
| Residential | 33 | $ 246 | -- | $ 1 | 33 | $ 247 |
| Commercial and industrial | 17 | 98 | 5 | 7 | 22 | 105 |
| Electric generation plants | - | - | 85 | 24 | 85 | 24 |
| | 50 | $ 344 | 90 | $ 32 | 140 | 376 |
| Balancing accounts and other | | | | | | 55 |
| Total | | | | | | $ 431 |

</table>

Although commodity-related revenues from the DWR's purchasing of SDG&E's net short position or from the DWR's allocated contracts are not included in revenue (as explained in Note 1 of the notes to Consolidated Financial Statements), the associated volumes and distribution revenue are included herein.

***Other Operating Expenses.*** Other operating expenses were $593 million, $637 million and $560 million in 2004, 2003 and 2002, respectively. The decrease in 2004 was due primarily to the favorable resolution of regulatory issues offset partially by higher litigation costs in 2004. The increase in 2003 compared to 2002 was due primarily to higher labor and employee benefit costs, costs associated with the Southern California wildfires and general operating cost increases, including litigation charges.

***Other Income.*** Other income and deductions consist primarily of interest income from short-term investments, interest income/expense from regulatory balancing accounts and allowance for equity funds used during construction. Excluding the impact of income taxes on non-operating income, other income was $43 million, $58 million and $22 million in 2004, 2003 and 2002, respectively. The decrease in 2004 was due to higher interest income in 2003 resulting from the favorable $37 million before-tax resolution of income-tax issues with the Internal Revenue Service (IRS), offset partially by interest earned on income tax receivables during 2004. The increase in 2003 compared to 2002 was due to the higher interest income and lower balancing account interest expense in 2003.

***Income Taxes.*** Income tax expense was $148 million for the years ended December 31, 2004 and 2003 and was $91 million for the year ended December 31, 2002. The effective income tax rates were 41.1 percent, 30.3 percent and 30.3 percent for the same years. The lower effective income tax rates in 2003 and 2002 were due primarily to the favorable resolution of income tax issues in both years. In addition, income before taxes in 2003 included $37 million in interest income arising from the income tax settlement, resulting in an offsetting $15 million income tax expense.

***Net Income.*** SDG&E recorded net income of $213 million, $340 million and $209 million, in 2004, 2003, and 2002, respectively. The decrease in 2004 was primarily due to the favorable resolution of income tax issues in 2003, which positively affected 2003 earnings by $79 million, income of $65 million after-tax in 2003 related to the approved settlement of intermediate-term purchase power contracts (discussed in Note 10 of the notes to Consolidated Financial Statements); the 2003 Incremental Cost Incentive Pricing income for the San Onofre Nuclear Generation Station (SONGS) ($53 million after-tax) and higher performance awards in 2003, offset by higher electric transmission and distribution margin in 2004 and the resolution of the 2004 cost of service proceeding, which favorable impacted net income by $21 million.

The increase in 2003 compared to 2002 was primarily due to more reductions in income tax expense in 2003 than in 2002 from favorable resolution of income tax issues, the approved settlement of the intermediate-term purchase power contracts, higher earnings from PBR awards, and higher electric transmission and distribution revenue. These factors were partially offset by the litigation costs and other operating expenses in 2003 and the end of sharing of the merger savings (which positively impacted earnings by $8 million in 2002).

**CAPITAL RESOURCES AND LIQUIDITY**

The company's operations are the major source of liquidity. In addition, working capital requirements can be met through the issuance of short-term and long-term debt. Cash requirements primarily consist of capital expenditures for utility plant.

At December 31, 2004, the company had $9 million in unrestricted cash and $300 million in available unused, committed lines of credit. Management believes that these amounts and cash flows from operations and new security issuances will be adequate to finance capital expenditures and meet liquidity requirements and other commitments. Forecasted capital expenditures for the next five years are discussed in "Future Capital Expenditures for Utility Plant."

Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activities in a manner consistent with its intention to maintain strong, investment-quality credit ratings. Rating agencies and others that evaluate a company's liquidity generally consider a company's capital expenditures and working capital requirements in comparison to cash from operations, available credit lines and other sources available to meet liquidity requirements.

**CASH FLOWS FROM OPERATING ACTIVITIES**

Net cash provided by operating activities totaled $445 million, $581 million and $757 million for 2004, 2003 and 2002, respectively.

The decrease in net cash provided by operating activities was primarily due to lower net income in 2004.

The decrease in cash flows from operations in 2003 compared to 2002 was attributable to changes in regulatory balancing accounts and higher tax payments, offset by a reduction in deferred income taxes and investment tax credits.

During 2004, the company made pension plan and other postretirement benefit plan contributions of $20 million and $8 million, respectively.

**CASH FLOWS FROM INVESTING ACTIVITIES**

Net cash used in investing activities totaled $299 million, $319 million and $611 million for 2004, 2003 and 2002, respectively. The decrease in cash used in investing activities in 2004 was due to greater than normal capital expenditures in 2003 as a result of the 2003 Southern California wildfires. The decrease in cash used in investing activities in 2003 compared to 2002 was primarily due to the $129 million repayment by Sempra Energy in 2003 compared to $199 million of advances from SDG&E in 2002, offset by the effects of the wildfires. Advances to Sempra Energy are payable on demand.

**Future Capital Expenditures for Utility Plant**

Significant capital expenditures in 2005 are expected to include $550 million for additions to the company's natural gas and electric distribution systems. These expenditures are expected to be financed by cash flows from operations and security issuances.

Over the next five years, the company expects to make capital expenditures of $3.2 billion, including $550 million in 2005, $1.0 billion in 2006, $450 million in 2007, $600 million in 2008 and $600 million in 2009. The 2006 amount includes $500 million for Palomar, which SDG&E will purchase from Sempra Generation after construction is completed.

Construction programs are periodically reviewed and revised by the company in response to changes in economic conditions, competition, customer growth, inflation, customer rates, the cost of capital, and environmental and regulatory requirements.

**CASH FLOWS FROM FINANCING ACTIVITIES**

Net cash used in financing activities totaled $285 million, $273 million and $309 million for 2004, 2003 and 2002, respectively.

The cash used in financing activities decreased in 2003 from 2002 due to lower repayments on long-term debt in 2003.

**Long-Term and Short-Term Debt**

In June 2004, the company issued $251 million of first mortgage bonds and applied the proceeds in July to refund an identical amount of first mortgage bonds and related tax-exempt industrial development bonds of a shorter maturity. The bonds secure the repayment of tax-exempt industrial development bonds of an identical amount, maturity and interest rate issued by the City of Chula Vista, the proceeds of which were loaned to the company and which are repaid with payments on the first mortgage bonds. The bonds were initially issued as auction-rate securities, but the company entered into floating-for-fixed interest-rate swap agreements that effectively changed the bonds' interest rates to fixed rates in September 2004. The swaps are set to expire in 2009.

Repayments on long-term debt in 2004 included $251 million of SDG&E's first mortgage bonds and $66 million of rate-reduction bonds.

Repayments on long-term debt in 2003 were for $66 million of rate-reduction bonds.

Repayments on long-term debt in 2002 included $38 million of first mortgage bonds and $66 million of rate-reduction bonds.

In May 2004, the California Utilities obtained a combined $500 million three-year syndicated revolving credit facility to replace their expiring 364-day facility of a like amount. No amounts were outstanding under this facility at December 31, 2004.

Notes 2 and 3 of the notes to Consolidated Financial Statements provide further discussion of debt activity and lines of credit.

**Dividends**

Common dividends paid to Sempra Energy were $205 million in 2004, compared to $200 million in each of 2003 and 2002.

The payment and amount of future dividends are within the discretion of the company's board of directors. The CPUC's regulation of SDG&E's capital structure limits the amounts that are available for loans and dividends to Sempra Energy from SDG&E. At December 31, 2004, the company could have provided a total (combined loans and dividends) of $160 million to Sempra Energy.

**Capitalization**

Total capitalization, including the current portion of long-term debt and excluding the rate-reduction bonds (which are non-recourse to the company), at December 31, 2004 was $2.3 billion. The debt-to-capitalization ratio was 39 percent at December 31, 2004.

**Commitments**

The following is a summary of the company's principal contractual commitments at December 31, 2004. Liabilities reflecting fixed-price contracts and other derivatives are excluded as they are primarily offset against regulatory assets and would be recovered from customers through the ratemaking process. Additional information concerning commitments is provided above and in Notes 3, 6, 9 and 12 of the notes to Consolidated Financial Statements.

<table>
<caption>

| (Dollars in millions) | 2005 | 2006 and 2007 | 2008 and 2009 | Thereafter | Total |
|---|---|---|---|---|---|
| <s> | <c> | <c> | <c> | <c> | <c> |
| Long-term debt | $ 66 | $ 132 | $ -- | $ 890 | $1,088 |
| Interest on debt (1) | 55 | 98 | 90 | 592 | 835 |
| Operating leases | 19 | 34 | 20 | 14 | 87 |
| Purchased-power contracts | 218 | 515 | 635 | 4,017 | 5,385 |
| Natural gas contracts | 17 | 37 | 24 | 128 | 206 |
| Preferred stock subject to mandatory redemption | 2 | 2 | 17 | -- | 21 |
| Construction commitments | 8 | 15 | 8 | 49 | 80 |
| SONGS decommissioning | 16 | 13 | 4 | 295 | 328 |
| Other asset retirement obligations | 4 | 7 | -- | -- | 11 |
| Pension and postretirement benefit obligations (2) | 52 | 115 | 125 | 348 | 640 |
| Environmental commitments | 4 | 8 | -- | -- | 12 |
| Totals | $ 461 | $ 976 | $ 923 | $6,333 | $8,693 |

(1) Based on rates in effect at December 31, 2004.
(2) Amounts are before reduction for the Medicare Part D subsidy and only include expected payments for the next 10 years.
</table>

**Credit Ratings**

Credit ratings of the company remained at investment grade levels in 2004. As of January 31, 2005, credit ratings for SDG&E were as follows:

| | Standard & Poor's | Moody's Investor Services, Inc. | Fitch |
|---|---|---|---|
| Secured debt | A+ | A1 | AA |
| Unsecured debt | A- | A2 | AA- |
| Preferred stock | BBB+ | Baa1 | A+ |
| Commercial paper | A-1 | P-1 | F1+ |

As of January 31, 2005, the company has a stable outlook rating from all three credit rating agencies.

**FACTORS INFLUENCING FUTURE PERFORMANCE**

Performance of the company will depend primarily on the ratemaking and regulatory process, electric and natural gas industry restructuring, and the changing energy marketplace. These factors are discussed in Notes 10 and 11 of the notes to Consolidated Financial Statements.

**Market Risk**

Market risk is the risk of erosion of the company's cash flows, net income, asset values and equity due to adverse changes in prices for various commodities, and in interest rates.

Sempra Energy has adopted corporate-wide policies governing its market risk management activities. Assisted by Sempra Energy’s Energy Risk Management Group (ERMG), Sempra Energy’s Energy Risk Management Oversight Committee (ERMOC), consisting of senior officers, oversees company-wide energy risk management activities and monitors the results of activities to ensure compliance with the company's stated energy risk management policies. Utility management receives daily information on positions and the ERMG receives information detailing positions creating market and credit risk for the company, consistent with affiliate rules. The ERMG independently measures and reports the market and credit risk associated with these positions. In addition, the ERMOC monitors energy price risk management 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 interval. The company has adopted the variance/covariance methodology in its calculation of VaR, and uses both the 95-percent and 99-percent confidence intervals. VaR is calculated independently by the ERMG for the company. Historical volatilities and correlations between instruments and positions are used in the calculation. As of December 31, 2004, the total VaR of the company's natural gas and power positions was not material.

The company uses energy and natural gas derivatives to manage natural gas and energy price risk associated with servicing its load requirements. The use of derivative financial instruments is subject to certain limitations imposed by company policy and regulatory requirements.

Revenue recognition is discussed in Note 1 and the additional market risk information regarding derivative instruments is discussed in Note 8 of the notes to Consolidated Financial Statements.

The following discussion of the company's primary market risk exposures as of December 31, 2004 includes a discussion of how these exposures are managed.

**Commodity Price Risk**

Market risk related to physical commodities is created by volatility in the prices and basis of natural gas and electricity. The company's market risk is impacted by changes in volatility and liquidity in the markets in which these commodities or related financial instruments are traded. The company is exposed, in varying degrees, to price risk primarily in the natural gas 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.

The company's market risk exposure is limited due to CPUC-authorized rate recovery of electric procurement and natural gas purchase, sale, intrastate transportation and storage activity. However, the company may, at times, be exposed to market risk as a result of SDG&E's natural gas PBR and electric procurement activities, which is discussed in Note 11 of the notes to Consolidated Financial Statements. If commodity prices were to rise too rapidly, it is likely that volumes would decline. This would increase the per-unit fixed costs, which could lead to further volume declines. The company manages its risk within the parameters of the company's market risk management framework. As of December 31, 2004, the company's exposure to market risk was not material.

**Interest Rate Risk**

The company is exposed to fluctuations in interest rates primarily as a result of its long-term debt. The company historically has funded operations through long-term debt issues with fixed interest rates and these interest rates are recovered in utility rates. Some recent debt offerings 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.

At December 31, 2004, the company had $1.1 billion of fixed-rate debt and no variable-rate debt. Interest on fixed-rate utility debt is fully recovered in rates on a historical cost basis and interest on variable-rate debt is provided for in rates on a forecasted basis. At December 31, 2004, SDG&E's fixed-rate debt had a one-year VaR of $138 million.

At December 31, 2004, the notional amount of interest-rate swap transactions totaled $251 million. Note 3 of the notes to Consolidated Financial Statements provides further information regarding interest-rate swap transactions.

In addition, the company is ultimately subject to the effect of interest-rate fluctuation on the assets of its pension plan and other postretirement plans.

**Credit Risk**

Credit risk is the risk of loss that would be incurred as a result of nonperformance by counterparties of their contractual obligations. As with market risk, the company has adopted corporate-wide policies governing the management of credit risk. Credit risk management is performed by the ERMG and the company's credit department and overseen by the ERMOC. Using rigorous models, the ERMG and the company calculate current and potential credit risk to counterparties on a daily basis and monitor actual balances in comparison to approved limits. The company avoids concentration of counterparties whenever possible, and management believes its credit policies associated with counterparties significantly reduce overall credit risk. These policies include an evaluation of prospective counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty, and other security such as lock-box liens and downgrade triggers.

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.

The company periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. The company would be exposed to interest-rate fluctuations on the underlying debt should counterparties to the agreement not perform. Additional information regarding the company's use of interest-rate swap agreements is provided above under "Interest Rate Risk."

**CRITICAL ACCOUNTING POLICIES AND KEY NON-CASH PERFORMANCE INDICATORS**

Certain accounting policies are viewed by management as critical because their application is the most relevant, judgmental and/or material to the company's financial position and results of operations, and/or because they require the use of material judgments and estimates.

The company's significant accounting policies are described in Note 1 of the notes to Consolidated Financial Statements. The most critical policies, all of which are mandatory under generally accepted accounting principles and the regulations of the Securities and Exchange Commission, are the following:

> *Statement of Financial Accounting Standards (SFAS) 5, "Accounting for Contingencies,"* establishes the amounts and timing of when the company provides for contingent losses. Details of the company's issues in this area are discussed in Note 12 of the notes to Consolidated Financial Statements.
>
> *SFAS 71, "Accounting for the Effects of Certain Types of Regulation,"* has a significant effect on the way the California Utilities record assets and liabilities, and the related revenues and expenses that would not be recorded absent the principles contained in SFAS 71.
>
> *SFAS 109, "Accounting for Income Taxes,"* governs the way the company provides for income taxes. Details of the company's issues in this area are discussed in Note 5 of the notes to Consolidated Financial Statements.
>
> *SFAS 123, "Accounting for Stock-Based Compensation" and SFAS 148 "Accounting for Stock-Based Compensation – Transition and Disclosure,"* give companies the choice of recognizing a cost at the time of issuance of stock options or merely disclosing what that cost would have been and not recognizing it in its financial statements. Sempra Energy has elected the disclosure option for all options that are so eligible. The effect of this is discussed in Note 1 of the notes to Consolidated Financial Statements.
>
> *SFAS 123R, "Share-Based Payment"* requires public companies to measure and record the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the awards and gives companies three methods to do so. This statement is effective for Sempra Energy on July 1, 2005. Further discussion is provided in Note 1 of the notes to Consolidated Financial Statements.

*SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" and SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities,"* have a significant effect on the balance sheets of the company but have no significant effect on its income statements because of the principles contained in SFAS 71.

In connection with the application of these and other accounting policies, the company makes estimates and judgments about various matters. The most significant of these involve:

The calculation of fair or realizable values.

The collectibility of receivables, regulatory assets, deferred tax assets and other assets.

The resolution of various income-tax issues between the company and the various taxing authorities.

The various assumptions used in actuarial calculations for pension and other postretirement benefit plans.

The probable costs to be incurred in the resolution of litigation.

Differences between estimates and actual amounts have had significant impacts in the past and are likely to have significant impacts in the future.

As discussed elsewhere herein, the company uses exchange quotations or other third-party pricing to estimate fair values whenever possible. When no such data is available, it uses internally developed models and other techniques. The assumed collectibility of receivables considers the aging of the receivables, the credit-worthiness of customers and the enforceability of contracts, where applicable. The assumed collectibility of regulatory assets considers legal and regulatory decisions involving the specific items or similar items. The assumed collectibility of other assets considers the nature of the item, the enforceability of contracts where applicable, the credit-worthiness of the other parties and other factors. The anticipated resolution of income-tax issues considers past resolution of the same or similar issue, the status of any income-tax examination in progress and positions taken by taxing authorities with other taxpayers with similar issues. Actuarial assumptions are based on the advice of the company's independent actuaries. The likelihood of deferred tax recovery is based on analyses of the deferred tax assets and the company's expectation of future financial and/or taxable income, based on its strategic planning.

Choices among alternative accounting policies that are material to the company's financial statements and information concerning significant estimates have been discussed with the audit committee of the board of directors.

Key non-cash performance indicators for the company include numbers of customers and quantities of natural gas and electricity sold. The information is provided in "Introduction" and "Results of Operations."

**NEW ACCOUNTING STANDARDS**

Relevant pronouncements that have recently become effective and have had a significant effect on the company’s financial statements are SFAS 132 (revised 2003), 143 and 150, and FIN 46. They are described in Note 1 of the notes to Consolidated Financial Statements. Pronouncements of particular importance to the company’s financial statements are described below.

*SFAS 143, "Accounting for Asset Retirement Obligations":* SFAS 143 requires entities to record the fair value of liabilities for legal obligations related to asset retirements in the period in which they are incurred. It also requires the company to reclassify amounts recovered in rates for future removal costs not covered by a legal obligation from accumulated depreciation to a regulatory liability.

*FIN 46, "Consolidation of Variable Interest Entities, an interpretation of ARB No. 51":* In January 2003, the FASB issued FIN 46 to strengthen existing accounting guidance that addresses when a company should consolidate a VIE in its financial statements.

Contracts under which SDG&E acquires power from generation facilities otherwise unrelated to SDG&E could result in a requirement for SDG&E to consolidate the entity that owns the facility. As permitted by the interpretation, SDG&E is continuing the process of determining whether it has any such situations and, if so, gathering the information that would be needed to perform the consolidation. The effects of this, if any, are not expected to significantly affect the financial position of SDG&E and there would be no effect on results of operations or liquidity.

**ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The information required by Item 7A is set forth under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk."

**ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED INCOME
(Dollars in millions)
<caption>

| | Years ended December 31, 2004 | 2003 | 2002 |
|---|---|---|---|
| Operating revenues | | | |
| Electric | $ 1,678 | $ 1,802 | $ 1,294 |
| Natural gas | 596 | 509 | 431 |
| Total operating revenues | 2,274 | 2,311 | 1,725 |
| Operating expenses | | | |
| Cost of electric fuel and purchased power | 576 | 541 | 297 |
| Cost of natural gas | 347 | 274 | 205 |
| Other operating expenses | 593 | 637 | 560 |
| Depreciation and amortization | 259 | 242 | 230 |
| Income taxes | 135 | 122 | 93 |
| Franchise fees and other taxes | 113 | 114 | 78 |
| Total operating expenses | 2,023 | 1,930 | 1,463 |
| Operating income | 251 | 381 | 262 |
| Other income and (deductions) | | | |
| Interest income | 25 | 42 | 10 |
| Regulatory interest - net | (6) | (5) | (7) |
| Allowance for equity funds used during construction | 9 | 12 | 15 |
| Income taxes on non-operating income | (13) | (26) | 2 |
| Other - net | 15 | 9 | 4 |
| Total | 30 | 32 | 24 |
| Interest charges | | | |
| Long-term debt | 61 | 67 | 75 |
| Other | 10 | 11 | 8 |
| Allowance for borrowed funds used during construction | (3) | (5) | (6) |
| Total | 68 | 73 | 77 |
| Net income | 213 | 340 | 209 |
| Preferred dividend requirements | 5 | 6 | 6 |
| Earnings applicable to common shares | $ 208 | $ 334 | $ 203 |

See notes to Consolidated Financial Statements.
</table>

<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
<caption>

| <s> | December 31, 2004 <c> | December 31, 2003 <c> |
|---|---|---|
| ASSETS | | |
| Utility plant - at original cost | $ 6,345 | $ 5,773 |
| Accumulated depreciation and amortization | (1,821) | (1,737) |
| Utility plant - net | 4,524 | 4,036 |
| Nuclear decommissioning trusts | 612 | 570 |
| Current assets: | | |
| Cash and cash equivalents | 9 | 148 |
| Accounts receivable - trade | 185 | 173 |
| Accounts receivable – other | 30 | 17 |
| Interest receivable | 55 | 37 |
| Due from unconsolidated affiliates | 30 | 151 |
| Regulatory assets arising from fixed-price contracts and other derivatives | 55 | 59 |
| Other regulatory assets | 77 | 81 |
| Inventories | 88 | 60 |
| Other | 31 | 27 |
| Total current assets | 560 | 753 |
| Other assets: | | |
| Deferred taxes recoverable in rates | 278 | 271 |
| Regulatory assets arising from fixed-price contracts and other derivatives | 448 | 502 |
| Other regulatory assets | 341 | 281 |
| Sundry | 71 | 48 |
| Total other assets | 1,138 | 1,102 |
| Total assets | $ 6,834 | $ 6,461 |

See notes to Consolidated Financial Statements.
</table>

<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
<caption>

| <s> | December 31, 2004 <c> | December 31, 2003 <c> |
|---|---|---|
| CAPITALIZATION AND LIABILITIES | | |
| Capitalization: | | |
| Common stock (255 million shares authorized; 117 million shares outstanding) | $ 938 | $ 938 |
| Retained earnings | 372 | 369 |
| Accumulated other comprehensive income (loss) | (13) | (43) |
| Total common equity | 1,297 | 1,264 |
| Preferred stock not subject to mandatory redemption | 79 | 79 |
| Total shareholders' equity | 1,376 | 1,343 |
| Long-term debt | 1,022 | 1,087 |
| Total capitalization | 2,398 | 2,430 |
| Current liabilities: | | |
| Accounts payable | 200 | 193 |
| Interest payable | 9 | 10 |
| Due to unconsolidated affiliate | 15 | -- |
| Income taxes payable | 225 | 217 |
| Deferred income taxes | 15 | 26 |
| Regulatory balancing accounts – net | 331 | 338 |
| Fixed-price contracts and other derivatives | 55 | 59 |
| Current portion of long-term debt | 66 | 66 |
| Other | 292 | 272 |
| Total current liabilities | 1,208 | 1,181 |
| Deferred credits and other liabilities: | | |
| Due to unconsolidated affiliates | 267 | 21 |
| Customer advances for construction | 45 | 49 |
| Deferred income taxes | 522 | 485 |
| Deferred investment tax credits | 37 | 40 |
| Regulatory liabilities arising from cost of removal obligations | 913 | 846 |
| Regulatory liabilities arising from asset retirement obligations | 333 | 303 |
| Fixed-price contracts and other derivatives | 448 | 502 |
| Asset retirement obligations | 318 | 303 |
| Mandatorily redeemable preferred securities | 19 | 21 |
| Deferred credits and other | 326 | 280 |
| Total deferred credits and other liabilities | 3,228 | 2,850 |
| Commitments and contingencies (Note 12) | | |
| Total liabilities and shareholders' equity | $ 6,834 | $ 6,461 |

See notes to Consolidated Financial Statements.
</table>

<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)
<caption>

| | Years ended December 31, 2004 | 2003 | 2002 |
|---|---|---|---|
| <S> | <C> | <C> | <C> |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income | $ 213 | $ 340 | $ 209 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 259 | 242 | 230 |
| Deferred income taxes and investment tax credits | -- | (29) | (127) |
| Non-cash rate reduction bond expense | 75 | 68 | 82 |
| Loss (gain) on disposition of assets | (1) | 4 | -- |
| Changes in other assets | (53) | -- | 123 |
| Changes in other liabilities | (21) | (6) | 46 |
| Changes in working capital components: | | | |
| Accounts receivable | (24) | (9) | 6 |
| Interest receivable | (18) | (37) | -- |
| Due to/from affiliates - net | 13 | 2 | (61) |
| Inventories | (27) | (14) | 23 |
| Other current assets | (1) | (23) | (6) |
| Income taxes | 15 | 8 | 127 |
| Accounts payable | 6 | 34 | 21 |
| Regulatory balancing accounts | (15) | (56) | 89 |
| Other current liabilities | 24 | 57 | (5) |
| Net cash provided by operating activities | 445 | 581 | 757 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Expenditures for property, plant and equipment | (414) | (444) | (400) |
| Affiliate loan | 122 | 129 | (199) |
| Contributions to decommissioning funds | (7) | (5) | (5) |
| Net proceeds from sale of assets | -- | 4 | -- |
| Other - net | -- | (3) | (7) |
| Net cash used in investing activities | (299) | (319) | (611) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Common dividends paid | (205) | (200) | (200) |
| Preferred dividends paid | (5) | (6) | (6) |
| Payments on long-term debt | (317) | (66) | (103) |
| Issuances of long-term debt | 251 | -- | -- |
| Redemptions of preferred stock | (3) | (1) | -- |
| Other – net | (6) | -- | -- |
| Net cash used in financing activities | (285) | (273) | (309) |
| Decrease in cash and cash equivalents | (139) | (11) | (163) |
| Cash and cash equivalents, January 1 | 148 | 159 | 322 |
| Cash and cash equivalents, December 31 | $ 9 | $ 148 | $ 159 |
| SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION | | | |
| Interest payments, net of amounts capitalized | $ 63 | $ 68 | $ 71 |
| Income tax payments, net of refunds | $ 129 | $ 167 | $ 92 |
| SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES | | | |
| Assets contributed by Sempra Energy | $ -- | $ 1 | $ 86 |
| Liabilities assumed | -- | (6) | -- |
| Net assets (liabilities) contributed by Sempra Energy | $ -- | $ (5) | $ 86 |

See notes to Consolidated Financial Statements.
</table>

<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2004, 2003 and 2002
(Dollars in millions)
<caption>

| | Comprehensive Income | Preferred Stock Not Subject to Mandatory Redemption | Common Stock | Retained Earnings | Accumulated Other Comprehensive Income(Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| <S> | <C> | <C> | <C> | <C> | <C> | <C> |
| Balance at December 31, 2001 | | $ 79 | $ 857 | $ 232 | $ (3) | $ 1,165 |
| Net income | $ 209 | | | 209 | | 209 |
| Other comprehensive income adjustment - pension | (31) | | | | (31) | (31) |
| Comprehensive income | $ 178 | | | | | |
| Preferred dividends declared | | | | (6) | | (6) |
| Common stock dividends declared | | | | (200) | | (200) |
| Capital contribution | | | 86 | | | 86 |
| Balance at December 31, 2002 | | 79 | 943 | 235 | (34) | 1,223 |
| Net income | $ 340 | | | 340 | | 340 |
| Other comprehensive income adjustment - pension | (9) | | | | (9) | (9) |
| Comprehensive income | $ 331 | | | | | |
| Preferred dividends declared | | | | (6) | | (6) |
| Common stock dividends declared | | | | (200) | | (200) |
| Capital contribution | | | (5) | | | (5) |
| Balance at December 31, 2003 | | 79 | 938 | 369 | (43) | 1,343 |
| Net income | $ 213 | | | 213 | | 213 |
| Other comprehensive income adjustment - pension | 30 | | | | 30 | 30 |
| Comprehensive income | $ 243 | | | | | |
| Preferred dividends declared | | | | (5) | | (5) |
| Common stock dividends declared | | | | (205) | | (205) |
| Balance at December 31, 2004 | | $ 79 | $ 938 | $ 372 | $ (13) | $ 1,376 |

See notes to Consolidated Financial Statements.
</table>

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

### Principles of Consolidation

The Consolidated Financial Statements include the accounts of San Diego Gas & Electric (SDG&E or the company) and its sole subsidiary, SDG&E Funding LLC. All material intercompany accounts and transactions have been eliminated.

As a subsidiary of Sempra Energy, the company receives certain services therefrom, for which it is charged its allocable share of the cost of such services. Management believes that cost is reasonable, but probably less than if the company had to provide those services itself.

### Use of Estimates in the Preparation of the Financial Statements

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

### Basis of Presentation

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

### Regulatory Matters

*Effects of Regulation*

The accounting policies of the company 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 its affiliate, Southern California Gas Company (SoCalGas), are collectively referred to herein as "the California Utilities."

The company prepares its financial statements in accordance with the provisions of SFAS 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. To the extent that recovery is no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets would be written off. In addition, SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires that a loss be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase. Regulatory liabilities represent reductions in future rates for amounts due to customers. Information concerning regulatory assets and liabilities is provided below in "Revenues," "Regulatory Balancing Accounts" and "Regulatory Assets and Liabilities."

*Regulatory Balancing Accounts*

The amounts included in regulatory balancing accounts at December 31, 2004, represent net payables (payables net of receivables) that are returned by reducing future rates.

Except for certain costs subject to balancing account treatment, fluctuations in most operating and maintenance accounts affect utility earnings. Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. The CPUC has also approved balancing account treatment for variances between forecast and actual for SDG&E’s commodity costs and volumes, eliminating the impact on earnings from any throughput and revenue variances from adopted forecast levels. Additional information on regulatory matters is included in Notes 10 and 11.

*Regulatory Assets and Liabilities*

In accordance with the accounting principles of SFAS 71, the company records regulatory assets and regulatory liabilities as discussed above.

Regulatory assets (liabilities) as of December 31 relate to the following matters:

| (Dollars in millions) | 2004 | 2003 |
|---|---|---|
| Fixed-price contracts and other derivatives | $ 500 | $ 560 |
| Recapture of temporary rate reduction* | 183 | 259 |
| Deferred taxes recoverable in rates | 278 | 271 |
| Unamortized loss on retirement of debt, net | 46 | 44 |
| Employee benefit costs | 160 | 35 |
| Cost of removal obligation** | (913) | (846) |
| Asset retirement obligation** | (333) | (303) |
| Other | 29 | 24 |
| Total | $ (50) | $ 44 |

* In connection with electric industry restructuring, which is described in Note 10, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2007.

** This is related to SFAS 143, *Accounting for Asset Retirement Obligations*, which is discussed below in "New Accounting Standards."

Net regulatory assets (liabilities) are recorded on the Consolidated Balance Sheets at December 31 as follows:

| (Dollars in millions) | 2004 | 2003 |
|---|---|---|
| Current regulatory assets | $ 132 | $ 140 |
| Noncurrent regulatory assets | 1,067 | 1,054 |
| Current regulatory liabilities* | (3) | (1) |
| Noncurrent regulatory liabilities | (1,246) | (1,149) |
| Total | $ (50) | $ 44 |

* Included in Other Current Liabilities.

All of these assets either earn a return, generally at short-term rates, or the cash has not yet been expended and the assets are offset by liabilities that do not incur a carrying cost.

**Cash and Cash Equivalents**

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

**Collection Allowances**

The allowance for doubtful accounts was $2 million, $2 million and $3 million at December 31, 2004, 2003 and 2002, respectively. The company recorded a provision for doubtful accounts of $3 million, $1 million and $4 million in 2004, 2003 and 2002, respectively.

**Inventories**

At December 31, 2004, inventory shown on the Consolidated Balance Sheets included natural gas of $50 million, and materials and supplies of $38 million. The corresponding balances at December 31, 2003 were $21 million and $39 million, respectively. Natural gas is valued by the last-in first-out (LIFO) method. When the inventory is consumed, differences between the LIFO valuation and replacement cost are reflected in customer rates. Materials and supplies at the company are generally valued at the lower of average cost or market.

**Income Taxes**

Income tax expense includes current and deferred income taxes from operations during the year. In accordance with SFAS 109, *Accounting for Income Taxes*, the company records deferred income taxes for temporary differences between the book and tax bases of assets and liabilities. Investment tax credits from prior years are being amortized to income over the estimated service lives of the properties. Other credits are recognized in income as earned. The company follows certain provisions of SFAS 109 that permit regulated enterprises to recognize deferred taxes as regulatory assets or liabilities if it is probable that such amounts will be recovered from, or returned to, customers.

**Property, Plant and Equipment**

Utility plant primarily represents the buildings, equipment and other facilities used by the company to provide natural gas and electric utility services.

The cost of plant includes labor, materials, contract services and certain expenditures, including refurbishments, replacement of major component parts and labor and overheads incurred to install the parts, incurred during a major maintenance outage of a generating plant. Maintenance costs are expensed as incurred. In addition, the cost of plant includes an allowance for funds used during construction (AFUDC). The cost of most retired depreciable utility plant minus salvage value is charged to accumulated depreciation.

Utility plant balances by major functional categories are as follows:

| (Dollars in billions) | Utility Plant at December 31, 2004 | Utility Plant at December 31, 2003 | Depreciation rates for years ended December 31, 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| Natural gas operations | $ 1.0 | $ 1.0 | 3.42% | 3.63% | 3.62% |
| Electric distribution | 3.4 | 3.2 | 4.11% | 4.70% | 4.66% |
| Electric transmission | 1.0 | 0.9 | 3.06% | 3.09% | 3.17% |
| Construction work in progress | 0.3 | 0.2 | | | |
| Other electric | 0.6 | 0.5 | 11.33% | 9.53% | 9.37% |
| Total | $ 6.3 | $ 5.8 | | | |

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $0.4 billion and $1.4 billion, respectively, at December 31, 2004, and were $0.3 billion and $1.4 billion, respectively, at December 31, 2003. The discussion of SFAS 143 under "New Accounting Standards" describes a change in presentation of accumulated depreciation. Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. Note 10 includes a discussion of the industry restructuring, which affected recorded depreciation.

AFUDC, which represents the cost of debt and equity funds used to finance the construction of utility plant, is added to the cost of utility plant. Although it is not a current source of cash, AFUDC increases income and is recorded partly as an offset to interest charges and partly as a component of Other Income and Deductions in the Statements of Consolidated Income. AFUDC amounted to $12 million, $17 million and $21 million for 2004, 2003 and 2002, respectively.

**Nuclear Decommissioning Liability**

At December 31, 2004 and 2003, as the result of implementing SFAS 143, the company had asset retirement obligations of $328 million and $316 million, respectively, and related regulatory liabilities of $333 million and $303 million, respectively. Additional information on San Onofre Nuclear Generating Station (SONGS) decommissioning costs is included below in "New Accounting Standards."

**Legal Fees**

Legal fees that are associated with a past event and not expected to be recovered in the future are accrued when it is probable that they will be incurred.

**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 foreign-currency translation adjustments, minimum pension liability adjustments and certain hedging activities. The components of other comprehensive income, which consists of all these changes other than net income as shown on the Statement of Consolidated Income, are shown in the Statements of Consolidated Changes in Shareholders' Equity. At December 31, 2004, the Accumulated Other Comprehensive Income consisted of minimum pension liability adjustments, net of income tax.

**Revenues**

Revenues are primarily derived from deliveries of electricity and natural gas to customers and changes in related regulatory balancing accounts. Revenues from electricity and natural gas sales and services are generally recorded under the accrual method and recognized upon delivery. The portion of SDG&E's electric commodity that was procured for its customers by the California Department of Water Resources (DWR) and delivered by SDG&E is not included in SDG&E's revenues or costs. Costs associated with long-term contracts allocated to SDG&E from the DWR were also not included in the Statements of Consolidated Income, since the DWR retains legal and financial responsibility for these contracts. Note 10 includes a discussion of the electric industry restructuring. Operating revenue includes amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

Through 2003, operating costs of SONGS Units 2 and 3, including nuclear fuel and related financing costs, and incremental capital expenditures were recovered through the Incremental Cost Incentive Pricing (ICIP) mechanism, which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affected net income. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. Beginning in 2004, the CPUC has provided for traditional rate-making treatment, under which the SONGS ratebase started over at January 1, 2004, essentially eliminating earnings from SONGS except from increases in ratebase in 2004 and beyond.

Additional information concerning utility revenue recognition is discussed above under "Regulatory Matters."

**Transactions with Affiliates**

On a daily basis, SDG&E and SoCalGas share numerous functions with each other and they also receive various services from and provide various services to Sempra Energy.

SDG&E has a promissory note receivable from Sempra Energy which bears a variable interest rate based on short-term commercial paper rates (2.01% at December 31, 2004), and is due on demand. The note balance (net of intercompany payables) was $96 million at December 31, 2003 and was paid off during 2004. In addition, at December 31, 2004 and 2003, SDG&E had $30 million and $55 million, respectively, due from affiliates. These amounts, including the promissory note described above, are included in Due from Unconsolidated Affiliates. Additionally, at December 31, 2004, SDG&E had $15 million due to affiliates, which is included in current liabilities. At December 31, 2004 and 2003, SDG&E had $267 million related to Palomar project which is not due to Sempra Generation until 2006 and $21 million due to Sempra Energy, respectively. These amounts are included in noncurrent liabilities as Due to Unconsolidated Affiliates.

**New Accounting Standards**

***SFAS 123 (revised 2004), "Share-Based Payment" (SFAS 123R):*** In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123R, a revision of SFAS 123, *Accounting for Stock-Based Compensation* (SFAS 123), which establishes the accounting for transactions in which an entity exchanges its equity instruments for goods or services received. This statement requires companies to measure and record the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award and gives companies three alternative transition methods. The modified prospective method requires companies to recognize compensation cost for unvested awards that are outstanding on the effective date based on the fair value that the company had originally estimated for purposes of preparing its SFAS 123 pro forma disclosures. For all new awards that are granted or modified after the effective date, a company would use SFAS 123R’s measurement model. The second alternative is a variation of the modified prospective method, allowing companies to restate earlier interim periods in the year that SFAS 123R is adopted using applicable SFAS 123 pro forma amounts. Under the third alternative, the modified retrospective method, companies would apply the modified prospective method, but also restate their prior financial statements to include the amounts that were previously reported in their pro forma disclosures under the original provisions of SFAS 123. Sempra Energy has not determined the transition method it will use. The effective date of this statement is July 1, 2005 for Sempra Energy.

***SFAS 132 (revised 2003), "Employers’ Disclosures about Pensions and Other Postretirement Benefits":*** This statement revised employers' disclosures about pension plans and other postretirement benefit plans. It requires disclosures beyond those in the original SFAS 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement plans. It does not change the measurement or recognition of those plans. Note 6 provides additional information on employee benefit plans.

***SFAS 143, "Accounting for Asset Retirement Obligations":*** Beginning in 2003, SFAS 143 requires entities to record liabilities for future costs expected to be incurred when assets are retired from service, if the retirement process is legally required. It requires recording of the estimated retirement cost over the life of the related asset by depreciating the present value of the obligation (measured at the time of the asset's acquisition) and by accreting the present value of the estimated future obligation over the asset's estimated useful life. The adoption of SFAS 143 on January 1, 2003 resulted in the recording of an addition to utility plant of $71 million, representing the company's share of SONGS’ estimated future decommissioning costs (as discounted to the present value at the dates the units began operation), and accumulated depreciation of $41 million related to the increase to utility plant, for a net increase of $30 million. It also requires the reclassification of estimated removal costs, which had historically been recorded in accumulated depreciation, to a regulatory liability. At December 31, 2004 and 2003, these costs were $913 million and $846 million, respectively. Implementation of SFAS 143 has had no effect on results of operations and is not expected to have a significant effect in the future.

On January 1, 2003, the company recorded additional asset retirement obligations of $10 million associated with the future retirement of a former power plant.

The changes in the asset retirement obligations for the years ended December 31, 2004 and 2003 are as follows (dollars in millions):

| | 2004 | 2003 |
|---|---|---|
| Balance as of January 1 | $ 326* | $ -- |
| Adoption of SFAS 143 | | 319 |
| Accretion expense | 23 | 21 |
| Payments | (10) | (14) |
| Balance as of December 31 | $ 339* | $ 326* |

* The current portion of the obligation is included in Other Current Liabilities on the Consolidated Balance Sheets.

In June 2004, the FASB issued a proposed interpretation, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143.* The interpretation would clarify that a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of SFAS 143. Accordingly, the interpretation would require an entity to recognize a liability for a conditional asset retirement obligation if the liability's fair value can be reasonably estimated. A final interpretation is expected to be issued by the FASB in the first quarter of 2005 and would be effective for the company on December 31, 2005. The company has not determined the effect the proposed interpretation would have on its financial statements if the proposed interpretation is adopted.

***SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"***: Effective July 1, 2003, SFAS 149 amended and clarified accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS 133. Under SFAS 149, natural gas forward contracts that are subject to unplanned netting generally do not qualify for the normal purchases and normal sales exception. ("Unplanned netting" refers to situations whereby contracts are settled by paying or receiving money for the difference between the contract price and the market price at the date on which physical delivery would have occurred. The "normal purchases and normal sales exception" provides for not marking to market contracts that are very rarely settled by means other than physical delivery of the commodity involved in the transaction.) In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 will continue to be marked to market. Implementation of SFAS 149 did not have a material impact on reported net income.

***SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"***: This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that certain mandatorily redeemable financial instruments previously classified in the mezzanine section of the balance sheet be reclassified as liabilities. The company adopted SFAS 150 beginning July 1, 2003 by reclassifying $24 million of mandatorily redeemable preferred stock to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets.

***SFAS 151, "Inventory Costs-an amendment of ARB No. 43, Chapter 4"***: This statement amends the guidance in Accounting Research Bulletin (ARB) No. 43, Chapter 4, *Inventory Pricing*, to clarify the accounting for abnormal amounts of idle facility expense, freight, handling cost, and wasted material. This statement requires that those items be recognized as current-period charges regardless of whether they meet the criteria of "abnormal." The statement is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The company does not expect that this statement will have a material impact on the company's financial statements.

***FIN 46, "Consolidation of Variable Interest Entities, an interpretation of ARB No. 51":*** FIN 46, as revised by FIN 46R, requires an enterprise to consolidate a variable interest entity (VIE), as defined in FIN 46, if the company is the primary beneficiary of a VIE's activities. Contracts under which SDG&E acquires power from generation facilities otherwise unrelated to SDG&E could result in a requirement for SDG&E to consolidate the entity that owns the facility. As permitted by the interpretation, SDG&E is continuing the process of determining whether it has any such situations and, if so, gathering the information that would be needed to perform the consolidation. The effects of this, if any, are not expected to significantly affect the financial position of SDG&E and there would be no effect on results of operations or liquidity.

***FASB Staff Position (FSP) 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"***: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was enacted in December of 2003. The Act establishes a prescription drug benefit under Medicare, known as "Medicare Part D," and a tax-exempt federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that actuarially is at least equivalent to Medicare Part D. At December 31, 2003, the company elected a one-time deferral of the accounting for the Act, as permitted by FSP 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*.

In May 2004, the FASB issued FSP 106-2, which supersedes FSP 106-1 and provides guidance on the accounting, disclosure, effective date and transition requirements related to the Medicare Prescription Drug Act. During 2004, the company adopted FSP 106-2 retroactive to the beginning of the year.

The company and its actuarial advisors determined that benefits provided to certain participants will actuarially be at least equivalent to Medicare Part D, and, accordingly, the company will be entitled to an expected tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2004 by $3 million and the net postretirement benefit cost for 2004 by an immaterial amount. Employee benefit plans are discussed further in Note 6.

## NOTE 2. SHORT-TERM BORROWINGS

### Committed Lines of Credit

SDG&E and its affiliate, SoCalGas, have a combined $500 million three-year syndicated revolving credit facility under which each utility individually may borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement bear interest at rates varying with market rates and SDG&E's credit rating. The agreement requires SDG&E to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as defined in the agreement) of no more than 60 percent. Borrowings under the agreement are individual obligations of the borrowing utility and a default by one utility would not constitute a default, or preclude borrowings by, the other. At December 31, 2004, SDG&E had no amounts outstanding under this facility.

## NOTE 3. LONG-TERM DEBT

| (Dollars in millions) | December 31, 2004 | December 31, 2003 |
|---|---|---|
| First mortgage bonds | | |
| 6.8% June 1, 2015 | $ 14 | $ 14 |
| 5.9% June 1, 2018 | 68 | 68 |
| 5.9% September 1, 2018 | 93 | 176 |
| 5.85% June 1, 2021 | 60 | 60 |
| 5.25% to 7% December 1, 2027 | 150 | 225 |
| After floating to fixed rate swap expiring 2009: | | |
| 2.516% to 2.832% January and February 2024 | 176 | -- |
| 2.8275% May 1, 2039 | 75 | -- |
| 6.1% September 1, 2019 | -- | 35 |
| Variable rates | -- | 58 |
| | 636 | 636 |
| Rate-reduction bonds, 6.31% to 6.37% at December 31, 2004 payable annually through 2007 | 198 | 263 |
| Other bonds | | |
| 5.9% June 1, 2014 | 130 | 130 |
| 5.3% July 1, 2021 | 39 | 39 |
| 5.5% December 1, 2021 | 60 | 60 |
| 4.9% March 1, 2023 | 25 | 25 |
| | 254 | 254 |
| | 1,088 | 1,153 |
| Current portion of long-term debt | (66) | (66) |
| Total | $1,022 | $1,087 |

Maturities of long-term debt are $66 million in each of 2005, 2006 and 2007, and $890 million after 2009.

Holders of variable-rate bonds may require the issuer to repurchase them prior to scheduled maturity. However, since repurchased bonds would be remarketed and funds for repurchase are provided by long-term revolving credit agreements (which are generally renewed upon expiration and which are described in Note 2), it is expected that the bonds will be held to the maturities stated above.

**Callable Bonds**

At the company's option, certain bonds are callable at various dates: $577 million in 2005 and $169 million thereafter.

**First Mortgage Bonds**

First mortgage bonds are secured by a lien on SDG&E's utility plant. SDG&E may issue additional first mortgage bonds upon compliance with the provisions of its bond indenture, which requires, among other things, the satisfaction of pro forma earnings-coverage tests on first mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of an additional $2.4 billion of first mortgage bonds at December 31, 2004.

In June 2004, the company issued $251 million of first mortgage bonds and applied the proceeds in July to refund an identical amount of first mortgage bonds and related tax-exempt industrial development bonds of a shorter maturity. The bonds secure the repayment of tax-exempt industrial development bonds of an identical amount, maturity and interest rate issued by the City of Chula Vista, the proceeds of which were loaned to the company and which are being repaid with payments on the first mortgage bonds. When SDG&E called the $251 million of refunded first mortgage bonds in July of 2004, it incurred $6 million in call premium costs. These costs were recorded as regulatory assets and are being amortized over the life of the retired debt. The bonds were initially issued as auction-rate securities, but the company entered into floating-for-fixed interest-rate swap agreements that effectively changed the refunding bonds' interest rates to fixed interest rates in September 2004. The swaps expire in 2009.

**Unsecured Long-term Debt**

Various long-term obligations totaling $254 million are unsecured at December 31, 2004.

**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%. These bonds were issued to facilitate the 10-percent rate reduction mandated by California's electric-restructuring law, which is described in Note 10. They are being repaid over ten years by SDG&E's residential and small-commercial customers through a specified 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.

**Interest-Rate Swaps**

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. As discussed above, in September 2004 SDG&E entered into interest-rate swaps to exchange the floating rates on its $251 million Chula Vista Series 2004 bonds for fixed rates.

**NOTE 4. FACILITIES UNDER JOINT OWNERSHIP**

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2004, are as follows:

| (Dollars in millions) | SONGS | Southwest Powerlink |
|---|---|---|
| Percentage ownership | 20% | 91% |
| Utility plant in service | $19 | $290 |
| Accumulated depreciation and amortization | $-- | $149 |
| Construction work in progress | $16 | $ 1 |

The company and the other owners each holds its interest as an undivided interest as tenants in common. Each owner is responsible for financing its share of each project and participates in decisions concerning operations and capital expenditures.

The company's share of operating expenses is included in the Statements of Consolidated Income.

**SONGS Decommissioning**

Objectives, work scope and procedures for the dismantling and decontamination of the SONGS units must meet the requirements of the Nuclear Regulatory Commission (NRC), 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 $328 million in 2004 dollars. Cost studies are updated every three years, with the next update expected to be submitted to the CPUC for its approval in 2006. Rate recovery of decommissioning costs is allowed until the time that the costs are fully recovered, and is subject to adjustment every three years based on the costs allowed by regulators. Collections are authorized to continue until 2013, at which time sufficient funds are expected to have been collected to fully decommission SONGS, but may be extended by CPUC approval until 2022, when the SONGS' operating license ends and the decommissioning of SONGS 2 and 3 would be expected to begin.

The amounts collected in rates are invested in externally managed trust funds. Amounts held by the trusts are invested in accordance with CPUC regulations that establish maximum amounts for investments in equity securities (50 percent of the qualified trust and 60 percent of the nonqualified trust), international equity securities (20 percent) and securities of electric utilities having ownership interests in nuclear power plants (10 percent). Not less than 50 percent of the equity portion of the trusts must be invested passively. The securities held by the trust are considered available for sale. These trusts are shown on the Consolidated Balance Sheets at market value. At December 31, 2004, these trusts reflected unrealized gains of $182 million with the offsetting credits recorded on the Consolidated Balance Sheets in Asset Retirement Obligations and the related regulatory liabilities.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled, removed and disposed of. Spent nuclear fuel has been removed from the Unit 1 Spent Fuel Pool and stored on-site in an Independent Spent Fuel Storage Facility (ISFSI) licensed by the NRC. The remaining major work will include dismantling, removal and disposal of all remaining Unit 1 equipment and facilities (both nuclear and non-nuclear components), and decontamination of the site. These activities are expected to be completed in 2008. The ISFSI and the reactor vessel will remain on site until a permanent storage facility becomes available.

Trust investments include:

| (Dollars in millions) | Maturity dates | December 31, 2004 | 2003 |
|---|---|---|---|
| Municipal Bonds | 2005 – 2034 | $ 45 | $ 47 |
| US government issues | 2005 – 2034 | 209 | 181 |
| Short-term cash and other | 2005 | 55 | 49 |
| Stocks | | 303 | 293 |
| Total | | $ 612 | $ 570 |

Net earnings (loss) were $45 million in 2004, $82 million in 2003 and $(25) million in 2002. Proceeds from sales of securities (which are reinvested) were $237 million in 2004, $266 million in 2003 and $409 million in 2002.

Customer contribution amounts are determined by estimates of after-tax investment returns, decommissioning costs and decommissioning cost escalation rates. Lower actual investment returns or higher actual decommissioning costs would result in an increase in future customer contributions.

Discussion regarding the impact of SFAS 143 is provided in Note 1. Additional information regarding SONGS is included in Notes 10 and 12.

**NOTE 5. INCOME TAXES**

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

| | Years ended December 31, 2004 | 2003 | 2002 |
|---|---|---|---|
| Statutory federal income tax rate | 35.0% | 35.0% | 35.0% |
| Depreciation | 3.9 | 3.9 | 2.3 |
| State income taxes, net of federal income tax benefit | 5.2 | 6.4 | 6.1 |
| Tax credits | (0.8) | (0.6) | (0.9) |
| Settlement of Internal Revenue Service audit | -- | (11.7) | (8.6) |
| Other, net | (2.2) | (2.7) | (3.6) |
| Effective income tax rate | 41.1% | 30.3% | 30.3% |

The components of income tax expense are as follows:

| (Dollars in millions) | Years ended December 31, 2004 | 2003 | 2002 |
|---|---|---|---|
| Current: | | | |
| Federal | $ 107 | $ 133 | $ 171 |
| State | 41 | 44 | 47 |
| Total | 148 | 177 | 218 |
| Deferred: | | | |
| Federal | 15 | (20) | (100) |
| State | (12) | (6) | (24) |
| Total | 3 | (26) | (124) |
| Deferred investment tax credits | (3) | (3) | (3) |
| Total income tax expense | $ 148 | $ 148 | $ 91 |

On the Statements of Consolidated Income, federal and state income taxes are allocated between operating income and other income.

SDG&E is included in the consolidated income tax return of Sempra Energy and is allocated income tax expense from Sempra Energy in an amount equal to that which would result from SDG&E's having always filed a separate return.

Accumulated deferred income taxes at December 31 relate to the following:

| (Dollars in millions) | 2004 | 2003 |
|---|---|---|
| Deferred tax liabilities: | | |
| Differences in financial and tax bases of utility plant | $ 575 | $ 561 |
| Regulatory balancing accounts | 74 | 132 |
| Loss on reacquired debt | 20 | 19 |
| Other | 16 | 10 |
| Total deferred tax liabilities | 685 | 722 |
| Deferred tax assets: | | |
| Investment tax credits | 27 | 29 |
| Deferred compensation | 29 | 76 |
| State income taxes | 19 | 24 |
| Federal benefit of state taxes | 24 | 29 |
| Workers compensation and public liability | 6 | 7 |
| Environmental liabilities | 11 | 5 |
| Other accruals not yet deductible | 30 | 38 |
| Other | 2 | 3 |
| Total deferred tax assets | 148 | 211 |
| Net deferred income tax liability | $ 537 | $ 511 |

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

| (Dollars in millions) | 2004 | 2003 |
| --- | --- | --- |
| Current liability | $ 15 | $ 26 |
| Noncurrent liability | 522 | 485 |
| Total | $ 537 | $ 511 |

**NOTE 6. EMPLOYEE BENEFIT PLANS**

**Pension and Other Postretirement Benefits**

The company has funded and unfunded noncontributory defined benefit plans that together cover substantially all of its employees. The plans provide defined benefits based on years of service and either final average or career salary.

The company also has other postretirement benefit plans covering substantially all of its employees. The life insurance plans are both contributory and noncontributory, and the health-care plans are contributory, with participants' contributions adjusted annually. Other postretirement benefits include retiree life insurance and medical benefits for retirees and their spouses.

There were no amendments to the company's pension and other postretirement benefit plans in 2003 or 2004. During 2002, the company had amendments to other postretirement benefit plans related to the transfer of employees from affiliates and changes to their specific benefits which resulted in a decrease in the benefits obligation of $7 million. The amortization of these changes will affect pension expense in future years.

December 31 is the measurement date for the pension and other postretirement benefit plans. The following table provides a reconciliation of the changes in the plans' projected benefit obligations during the latest two years, the fair value of assets and a statement of the funded status as of the latest two year ends:

<table>
<caption>

| (Dollars in millions) | Pension Benefits 2004 | Pension Benefits 2003 | Other Postretirement Benefits 2004 | Other Postretirement Benefits 2003 |
|---|---|---|---|---|
| <s> | <c> | <c> | <c> | <c> |
| CHANGE IN PROJECTED BENEFIT OBLIGATION: | | | | |
| Net obligation at January 1 | $ 662 | $ 613 | $ 76 | $ 60 |
| Service cost | 9 | 14 | 3 | 2 |
| Interest cost | 41 | 40 | 5 | 4 |
| Actuarial loss | 40 | 49 | 6 | 14 |
| Transfer of liability from Sempra Energy | 28 | 7 | -- | -- |
| Benefit payments | (61) | (61) | (5) | (4) |
| Net obligation at December 31 | 719 | 662 | 85 | 76 |
| CHANGE IN PLAN ASSETS: | | | | |
| Fair value of plan assets at January 1 | 538 | 468 | 34 | 28 |
| Actual return on plan assets | 65 | 107 | 2 | 3 |
| Employer contributions | 20 | 17 | 8 | 7 |
| Transfer of assets from Sempra Energy | 7 | 7 | -- | -- |
| Benefit payments | (61) | (61) | (5) | (4) |
| Fair value of plan assets at December 31 | 569 | 538 | 39 | 34 |
| Benefit obligation, net of plan assets at December 31 | (150) | (124) | (46) | (42) |
| Unrecognized net actuarial loss | 94 | 53 | 19 | 17 |
| Unrecognized prior service cost | 7 | 9 | (7) | (8) |
| Net recorded liability at December 31 | $ (49) | $ (62) | $ (34) | $ (33) |

</table>

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

<table>
<caption>

| (Dollars in millions) | Pension Benefits 2004 | Pension Benefits 2003 | Other Postretirement Benefits 2004 | Other Postretirement Benefits 2003 |
|---|---|---|---|---|
| <s> | <c> | <c> | <c> | <c> |
| Prepaid benefit cost | $ 6 | $ -- | $ -- | $ -- |
| Accrued benefit cost | (55) | (62) | (34) | (33) |
| Additional minimum liability | (90) | (61) | -- | -- |
| Intangible asset | 6 | 9 | -- | -- |
| Regulatory asset | 62 | -- | -- | -- |
| Accumulated other comprehensive income, pretax | 22 | 52 | -- | -- |
| Net recorded liability | $ (49) | $ (62) | $ (34) | $ (33) |

</table>

At December 31, 2004 and 2003, the company had an unfunded pension plan and a funded pension plan. The funded plan had benefit obligations in excess of its plan assets. The following table provides information for the funded plan at December 31:

| (Dollars in millions) | 2004 | 2003 |
|---|---|---|
| Projected benefit obligation | $ 694 | $ 662 |
| Accumulated benefit obligation | $ 692 | $ 661 |
| Fair value of plan assets | $ 569 | $ 538 |

The following table provides the components of net periodic benefit costs (income) for the years ended December 31:

| (Dollars in millions) | Pension Benefits 2004 | Pension Benefits 2003 | Pension Benefits 2002 | Other Postretirement Benefits 2004 | Other Postretirement Benefits 2003 | Other Postretirement Benefits 2002 |
|---|---|---|---|---|---|---|
| Service cost | $ 9 | $ 14 | $ 16 | $ 3 | $ 2 | $ 1 |
| Interest cost | 41 | 40 | 40 | 5 | 4 | 4 |
| Expected return on assets | (40) | (33) | (43) | (3) | (1) | (1) |
| Amortization of: | | | | | | |
| Transition obligation | -- | -- | -- | -- | 1 | 1 |
| Prior service cost | 2 | 3 | 3 | (1) | (1) | (1) |
| Actuarial (gain) loss | 1 | 2 | 1 | 1 | 1 | -- |
| Regulatory adjustment | (55) | -- | -- | (8) | -- | 1 |
| Total net periodic benefit cost (income) | $ (42) | $ 26 | $ 17 | $ (3) | $ 6 | $ 5 |

As described in Note 1, the company adopted FSP 106-2 in 2004 retroactive to the beginning of the year. The company and its actuarial advisors determined that benefits provided to certain participants will actuarially be at least equivalent to Medicare Part D, and, accordingly, the company will be entitled to an expected tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2004 by $3 million ($2 million of which applies to payments during the next 10 years) and the net postretirement benefit cost for 2004 by an immaterial amount.

The significant assumptions related to the company's pension and other postretirement benefit plans are as follows:

| Benefits | Pension Benefits 2004 | Pension Benefits 2003 | Other Postretirement 2004 | Other Postretirement 2003 |
|---|---|---|---|---|
| WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31: | | | | |
| Discount rate | 5.66% | 6.00% | 5.66% | 6.00% |
| Rate of compensation increase | 4.50% | 4.50% | 4.50% | 4.50% |
| WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31: | | | | |
| Discount rate | 6.00% | 6.50% | 6.00% | 6.50% |
| Expected return on plan assets | 7.50% | 7.50% | 4.76% | 3.75% |
| Rate of compensation increase | 4.50% | 4.50% | 4.50% | 4.50% |

The expected long-term rate of return on plan assets is derived from historical returns for broad asset classes consistent with expectations from a variety of sources, including pension consultants and investment advisors.

<table>
<caption>

| | 2004 | 2003 |
|---|---|---|
| <s> | <c> | <c> |
| ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31: | | |
| Health-care cost trend rate | 19.00% * | 30.00% * |
| Rate to which the cost trend rate is assumed to decline (the ultimate trend) | 5.50% | 5.50% |
| Year that the rate reaches the ultimate trend | 2008 | 2008 |

* This is the weighted average of the increases for all health plans. The rate for these plans ranged from 10% to 20% in 2004 and from 15% to 40% in 2003, respectively.
</table>

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

<table>
<caption>

| (Dollars in millions) | 1% Increase | 1% Decrease |
|---|---|---|
| <s> | <c> | <c> |
| Effect on total of service and interest cost components of net periodic postretirement health-care benefit cost | $ 1 | $ -- |
| Effect on the health-care component of the accumulated other postretirement benefit obligation | $ 5 | $ 4 |

</table>

**Pension Plan Investment Strategy**

The asset allocation for Sempra Energy’s pension trust (which includes SDG&E’s pension plan) at December 31, 2004 and 2003 and the target allocation for 2005 by asset categories are as follows:

<table>
<caption>

| | Target Allocation | Percentage of Plan Assets at December 31, | |
|---|---|---|---|
| Asset Category | 2005 | 2004 | 2003 |
| <s> | <c> | <c> | <c> |
| U.S. Equity | 45% | 45% | 45% |
| Foreign Equity | 25 | 32 | 30 |
| Fixed Income | 30 | 23 | 25 |
| Total | 100% | 100% | 100% |

</table>

The company's investment strategy is to stay fully invested at all times and maintain its strategic asset allocation, keeping the investment structure relatively simple. The equity portfolio is balanced to maintain risk characteristics similar to the S&P 1500 with respect to market capitalization, and industry and sector exposures. The foreign equity portfolios are managed to track the MSCI Europe, Pacific Rim and Emerging Markets indexes. Bond portfolios are managed with respect to the Lehman Aggregate Index. The plan does not invest in Sempra Energy securities.

**Investment Strategy for Postretirement Health Plans**

The asset allocation for the company's postretirement health plans at December 31, 2004 and 2003 and the target allocation for 2005 by asset categories are as follows:

| Asset Category | Target Allocation 2005 | Percentage of Plan Assets at December 31, 2004 | 2003 |
|---|---|---|---|
| U.S. Equity | 25% | 25% | 26% |
| Foreign Equity | 5 | 6 | 5 |
| Fixed Income | 70 | 69 | 69 |
| Total | 100% | 100% | 100% |

The company's postretirement health plans, which also are distinct from other postretirement benefit plans included in Sempra Energy's pension trust (shown above), pay premiums to the health maintenance organization and point-of-service plans from company and participant contributions. The company's investment strategy is to match the long-term growth rate of the liability primarily through the use of tax-exempt California municipal bonds.

**Future Payments**

The company expects to contribute $22 million to the pension plan and $9 million to its other postretirement benefit plans in 2005.

The following table reflects the total benefits expected to be paid for the next 10 years to current employees and retirees from the plans or from the company's assets, including both the company's share of the benefit cost and, where applicable, the participants' share of the costs, which is funded by participant contributions to the plans.

| (Dollars in millions) | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| 2005 | $ 46 | $ 6 |
| 2006 | $ 49 | $ 7 |
| 2007 | $ 52 | $ 7 |
| 2008 | $ 55 | $ 7 |
| 2009 | $ 56 | $ 7 |
| 2010-2014 | $ 311 | $ 37 |

**Savings Plan**

The company offers a trusteed savings plan to all eligible employees. Eligibility to participate in the plan is immediate for salary deferrals. Employees may contribute, subject to plan provisions, from one percent to 25 percent of their regular earnings. After one year of completed service, the company begins to make matching contributions. Employer contributions are equal to 50 percent of the first 6 percent of eligible base salary contributed by employees and, if certain company goals are met, an additional amount related to incentive compensation payments.

Employer contributions are invested in Sempra Energy common stock and had been required to remain so invested until termination of employment or until the employee's attainment of age 55, when they could be transitioned into other investments. Effective January 1, 2005, all employees have the ability to transfer employer contributions into other investments. The employees' contributions are invested in Sempra Energy stock, mutual funds, or institutional trusts (the same investments in which employees may now direct the employer contributions). Company contributions to the savings plan were $10 million in 2004, $8 million in 2003 and $7 million in 2002.

**NOTE 7. STOCK-BASED COMPENSATION**

Sempra Energy has stock-based compensation plans intended to align employee and shareholder objectives related to the long-term growth of the company. The plans permit a wide variety of stock-based awards, including nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, performance awards, stock payments and dividend equivalents.

In 1995, SFAS 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 123, Sempra Energy and its subsidiaries adopted only its disclosure requirements and continue to account for stock-based compensation in accordance with the provisions of Accounting Principles Board Opinion 25. Discussion of SFAS 123R (a revision of SFAS 123) is provided in Note 1. The subsidiaries record an expense for the plans to the extent that subsidiary employees participate in the plans or that subsidiaries are allocated a portion of Sempra Energy's costs of the plans. SDG&E recorded expenses of $9 million, $7 million and $1 million in 2004, 2003 and 2002, respectively.

## NOTE 8. FINANCIAL INSTRUMENTS

### Fair Value

The fair values of certain of the company's financial instruments (cash, temporary investments, notes receivable and customer deposits) approximate their carrying amounts. The following table provides the carrying amounts and fair values of the remaining financial instruments at December 31:

<table>
<caption>

| (Dollars in millions) | 2004 Carrying Amount | 2004 Fair Value | 2003 Carrying Amount | 2003 Fair Value |
|---|---|---|---|---|
| <s> | <c> | <c> | <c> | <c> |
| First mortgage bonds | $ 636 | $ 665 | $ 636 | $ 653 |
| Rate-reduction bonds | 198 | 241 | 263 | 284 |
| Other long-term debt | 254 | 273 | 254 | 278 |
| Total long-term debt | $ 1,088 | $ 1,179 | $ 1,153 | $ 1,215 |
| Preferred stock | $ 100* | $ 100 | $ 103* | $ 100 |

* $21 million and $24 million in 2004 and 2003, respectively, of mandatorily redeemable preferred stock is included in Deferred Credits and Other Liabilities and in Other Current Liabilities on the Consolidated Balance Sheets.

</table>

The fair values of long-term debt and preferred stock are based on their quoted market prices or quoted market prices for similar securities.

### Accounting for Derivative Instruments and Hedging Activities

The company follows the guidance of SFAS 133 and related amendments SFAS 138 and 149 (collectively SFAS 133) to account for its derivative instruments and hedging activities. Derivative instruments and related hedges are recognized as either assets or liabilities on the balance sheet, measured at fair value. Changes in the fair value of derivatives are recognized in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged; therefore, there is no effect on net income. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is similarly reflected. The ineffective portion is reported in earnings immediately. The effect on other comprehensive income for the years ended December 31, 2004 and 2003 was not material. In instances where derivatives do not qualify for hedge accounting, gains and losses are recorded in earnings immediately.

The company utilizes natural gas and energy derivatives to manage commodity price risk associated with servicing its load requirements. These contracts allow the company to predict with greater certainty the effective prices to be received by the company and the prices to be charged to its customers. The use of derivative financial instruments is subject to certain limitations imposed by company policy and regulatory requirements. The company classifies its forward contracts as follows:

Contracts that meet the definition of normal purchase and sales, i.e., those that rarely settle by means other than physical delivery of the commodities involved in the transaction, are eligible for the normal purchases and sales exception of SFAS 133, whereby they are accounted for under accrual accounting and recorded in Revenues or Cost of Sales on the Statements of Consolidated Income at the time of delivery. Due to the adoption of SFAS 149, the company has determined that its natural gas contracts entered into after June 30, 2003 generally do not qualify for the normal purchases and sales exception.

Electric and Natural Gas Purchases and Sales: The unrealized gains and losses related to these forward contracts are offset by regulatory assets and liabilities on the Consolidated Balance Sheets to the extent derivative gains and losses will be recoverable or payable in future rates. If gains and losses are not recoverable or payable through future rates, the company applies hedge accounting if certain criteria are met. When a contract no longer meets the requirements of SFAS 133, the unrealized gains and losses and the related regulatory asset or liability will be amortized over the remaining contract life.

The following were recorded in the Consolidated Balance Sheets at December 31 related to derivatives:

<table>
<caption>

| (Dollars in millions) | 2004 | 2003 |
|---|---|---|
| <s> | <c> | <c> |
| Fixed-price Contracts and Other Derivatives: | | |
| Current liabilities | $ 55 | $ 59 |
| Noncurrent liabilities | 448 | 502 |
| Total | 503 | 561 |
| Other current assets | 3 | 1 |
| Net liabilities | $ 500 | $ 560 |

</table>

Regulatory assets and liabilities related to derivatives held by SDG&E at December 31 were:

| (Dollars in millions) | 2004 | 2003 |
|---|---|---|
| Regulatory Assets and Liabilities: | | |
| Current regulatory assets | $ 55 | $ 59 |
| Noncurrent regulatory assets | 448 | 502 |
| Total | 503 | 561 |
| Current regulatory liabilities | 3 | 1 |
| Net | $ 500 | $ 560 |

The above had no impact on net income during 2004 and 2003.

**Market Risk**

The company's policy is to use derivative physical and financial instruments to reduce its exposure to fluctuations in interest rates and commodity prices. Transactions involving these instruments are with major exchanges and other firms believed to be credit-worthy. The use of these instruments exposes the company to market and credit risk, which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated.

**Interest-Rate Risk Management**

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower the overall cost of borrowing. This is described in Note 3.

**Energy Contracts**

SDG&E records transactions for natural gas and electric energy contracts in Cost of Natural Gas and Cost of Electric Fuel and Purchased Power, respectively, in the Statements of Consolidated Income. For open contracts not expected to result in physical delivery, changes in market value of the contracts are recorded in these accounts during the period the contracts are open, with an offsetting entry to a regulatory asset or liability. The majority of the company's contracts result in physical delivery.

**NOTE 9. PREFERRED STOCK**

<table>
<caption>

| | Call/Redemption Price | December 31, 2004 | December 31, 2003 |
|---|---|---|---|
| | | (in millions) | |
| <s> | <c> | <c> | <c> |
| Not subject to mandatory redemption: | | | |
| $20 par value, authorized 1,375,000 shares: | | | |
| 5% Series, 375,000 shares outstanding | $ 24.00 | $ 8 | $ 8 |
| 4.5% Series, 300,000 shares outstanding | $ 21.20 | 6 | 6 |
| 4.4% Series, 325,000 shares outstanding | $ 21.00 | 7 | 7 |
| 4.6% 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 | | $ 79 | $ 79 |
| Subject to mandatory redemption: | | | |
| Without par value: $1.7625 Series, 850,000 and 950,000 shares outstanding at December 31, 2004 and December 31, 2003, respectively | $ 25.00 | $ 21* | $ 24* |

* At December 31, 2004 and 2003, $19 million and $21 million, respectively, were included in Deferred Credits and Other Liabilities and $2 million and $3 million, respectively, were included in Other Current Liabilities on the Consolidated Balance Sheets.

</table>

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 plus any unpaid dividends. 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 callable at December 31, 2004. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share per year from 2005 to 2007; all remaining shares must be redeemed in 2008. On January 15, 2005, SDG&E redeemed 100,000 shares.

**NOTE 10. ELECTRIC INDUSTRY REGULATION**

**Background**

The restructuring of California's electric utility industry has significantly affected the company's electric utility operations, and the power crisis of 2000-2001 caused the CPUC to significantly modify its plan for restructuring the electricity industry. Supply/demand imbalances and a number of other factors resulted in abnormally high electric-commodity prices beginning in mid-2000 and continuing into 2001. These higher prices were initially passed through to customers and resulted in bills that in most cases were double or triple those from 1999 and early 2000. This resulted in several legislative and regulatory responses, including California Assembly Bill (AB) 265. AB 265 imposed a ceiling on the cost of the electric commodity that SDG&E could pass on to its small-usage customers from June 1, 2000 to December 31, 2002.

SDG&E accumulated the amount that it paid for electricity in excess of the ceiling rate in an interest-bearing balancing account (the AB 265 undercollection, which is included in Regulatory Balancing Accounts, Net on the Consolidated Balance Sheets) and began recovering these amounts in rates charged to customers following the end of the rate-ceiling period. The remaining AB 265 undercollection was fully collected in 2004.

Another legislative response to the power crisis resulted in the purchase by the DWR of a substantial portion of the power requirements of California's electricity users. In 2001, the DWR entered into long-term contracts with suppliers to provide power for the utility procurement customers of each of the California investor-owned utilities (IOUs). The CPUC has established the allocation of the power and its administrative responsibility, including collection of power contract costs from utility customers, among the IOUs. Beginning on January 1, 2003, the IOUs resumed responsibility for electric commodity procurement above their allocated share of the DWR's long-term contracts.

**Department of Water Resources**

The DWR's operating agreement with SDG&E, approved by the CPUC, provides that SDG&E is acting as a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions under the DWR contracts allocated to SDG&E's customers. Legal and financial responsibility associated with these activities continues to reside with the DWR. Therefore, the revenues and costs associated with the contracts are not included in the Statements of Consolidated Income.

In October 2003, the CPUC initiated a proceeding to consider a permanent methodology for allocating the DWR's revenue requirement beginning in 2004 through the remaining life of the DWR contracts. On December 2, 2004, the CPUC issued a decision that would shift $790 million of the costs to SDG&E's customers over the period between implementation of the decision and 2013. On December 20, 2004, SDG&E filed an application for rehearing of the decision, arguing that the CPUC reached its decision without the proper evidentiary review of the method of calculating above-market costs. On January 13, 2005, the CPUC acted to grant rehearing on that limited issue.

Such a shift would not affect SDG&E's net income, but would adversely affect its customers' commodity costs. In the near term, the effect on SDG&E's cash flows would be minor, but could become significant in the later years unless rate ceilings imposed by AB 1X, which freeze total rates for most residential customers at the February 2001 level, are increased to provide more-contemporaneous recovery. Until January 1, 2016, CPUC Decision 04-12-048 provides SDG&E with a true-up triggering mechanism when an overcollection or undercollection in SDG&E's power procurement balancing account exceeds approximately five percent of the prior year's recorded electric commodity revenue.

**Power Procurement and Resource Planning**

In 2001, the CPUC directed the IOUs to resume electric commodity procurement to cover their net short energy requirements by January 1, 2003 and also implemented legislation regarding procurement and renewables portfolio standards. In addition, the CPUC established a process for review and approval of the utilities' long-term resource and procurement plans, which is intended to identify forecasted needs for generation and transmission resources within a utility's service territory to support transmission grid reliability and to serve customers. An updated 10-year resource plan was approved by the CPUC in December 2004, in a proceeding to consider utility resource planning, including energy efficiency, contracted power, demand response, qualifying facilities, renewable generation and distributed generation. SDG&E's updated long-term resource plan incorporates the resources approved by the CPUC that are discussed below, and recognizes updated CPUC goals to reach a 20-percent renewable resources target by 2010. The updated plan recommends a 500-kilovolt (kV) transmission line addition in 2010, which would be processed for approval in a subsequent CPUC proceeding. The CPUC also endorsed SDG&E's continued analysis and planning for a 500-kV transmission line, adopted SDG&E's proposal for cost recovery related to utility-owned generation, recognized the debt-equivalent impact associated with long-term power purchase contracts, adopted a greenhouse gas adder for assessing new resource acquisitions, and established a cap on initial costs for new utility-owned generation resources to level the playing field with respect to power purchase options. The estimated cost related to this updated plan is $700 million, to be spent by 2008, for capital projects approved by the CPUC in June 2004, as described below.

On June 9, 2004, the CPUC approved SDG&E's entering into five new electric resource contracts (including two under which SDG&E would take ownership, on a turnkey basis, of new generating assets, including the 550-MW combined-cycle Palomar plant being developed by Sempra Generation, an affiliate, for completion in 2006). An additional, demand-response contract was also approved. The decision authorized SDG&E to recover the costs of both contracted resources and turnkey resources, but did not adopt SDG&E's specific cost recovery, ratemaking and revenue requirement proposals for the proposed turnkey resources. On July 15, 2004, three parties filed requests for rehearing of the decision. SDG&E filed its response on July 30, 2004, opposing the requests. The CPUC is expected to rule on the requests by mid-2005. In September 2004, SDG&E filed its revenue requirement and ratemaking proposals for the 45-MW combustion turbine which SDG&E will acquire as a turnkey project and filed its revenue requirement and ratemaking proposals for the Palomar plant on November 1, 2004. On January 27, 2005, the CPUC approved the revenue requirement and ratemaking proposals for the 45-MW combustion turbine. The June 9, 2004, decision did not approve SDG&E's proposals for a return on equity (ROE) for SDG&E's new generation investments higher than SDG&E's ROE on distribution assets, an equity offset for the debt equivalent of purchase power contracts or an equity buildup for construction. These matters may be re-introduced for consideration in future CPUC proceedings.

**SONGS**

Southern California Edison's (Edison) CPUC decision on its 2003 General Rate Case application sets rates for SONGS, 20 percent of which is owned by SDG&E. Through December 31, 2003, the operating and capital costs of SONGS Units 2 and 3 were recovered through the ICIP mechanism which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. SDG&E's SONGS ratebase restarted at $0 on January 1, 2004 and, therefore, SDG&E's earnings from SONGS are now generally limited to a return on new capital additions.

Edison has applied for CPUC approval to replace SONGS' steam generators, which would require an estimated capital expenditure of $782 million. Hearings before the CPUC on Edison's application were completed on February 11, 2005 and a final decision addressing the cost effectiveness of the steam generator project is expected during the second half of 2005. SDG&E had elected not to participate in the project. SDG&E nonparticipation would result in a reduction in its share ownership in the project and a proportionate reduction in its share of SONGS' output. On February 18, 2005, an arbitrator issued a decision that, based upon Edison's cost calculations, would result in SDG&E's interest in SONGS being reduced to zero if SDG&E continues to decline to participate in the project. The arbitration decision is subject to CPUC review and approval, with a CPUC decision expected in the second half of 2006. The CPUC could require SDG&E to participate in the project or, if the reductions of SDG&E's ownership percentage resulting from the CPUC final decision were to be unacceptable, SDG&E may elect to participate.

During the most recent SONGS Unit 3 refueling outage which ended on December 28, 2004, Edison reported that it had performed inspections of two pressurizer sleeves and found evidence of degradation. Degradation of the pressurizer sleeves has been a concern in the nuclear industry for some time. Edison had been planning to replace all of the sleeves in Units 2 and 3 during the next refueling for each unit in 2005 and 2006, but decided to move the planned replacement of Unit 3's pressurizer sleeves forward from 2006 to 2004. This extra work lengthened the 2004 outage, but allowed Edison to move the 2006 refueling outage out of the peak summer period to the fall or winter of 2006. Edison reported that it will incur about $9 million of capital expenditures during 2005 that otherwise would have occurred in 2006. SDG&E's share would be approximately $2 million. Edison plans to replace the pressurizer sleeves in Unit 2 during its next scheduled outage in 2005.

Also during the 2004 outage, Edison reported that it had conducted a planned inspection of the Unit 3 reactor vessel head and found indications of degradation. Although the degradation is far below the level at which leakage would occur, Edison made the repairs during the 2004 outage. While Edison reports that this is the first experience at SONGS of this kind of degradation to the reactor vessel heads, the detection and repair of similar degradation at other plants are now common in the industry. Edison reports that it plans to replace the Unit 2 and Unit 3 reactor vessel heads during refueling outages in 2009-2010.

**Spent Nuclear Fuel**

SONGS owners have responsibility for the interim storage of spent nuclear fuel generated at SONGS until it is accepted by the Department of Energy (DOE) for final disposal. Spent nuclear fuel has been stored in the SONGS Units 1, 2 and 3 spent fuel pools and the ISFSI. Movement of all spent fuel to the ISFSI was completed as of December 31, 2004, except for the movement of Unit 1 spent fuel stored at the Unit 2 spent fuel pool, which is expected to be completed by the end of 2005. With these moves, there will be sufficient space for the Units 2 and 3 spent fuel pools to meet requirements through mid-2007 and mid-2008, respectively.

## NOTE 11. OTHER REGULATORY MATTERS

### Natural Gas Industry Restructuring (GIR)

In December 2001, the CPUC issued a decision related to GIR, with implementation anticipated during 2002. On April 1, 2004, after many delays and changes, the CPUC issued a decision that adopts tariffs to implement the 2001 decision. However, by that same decision, the CPUC stayed implementation of the GIR tariffs until it issues a decision in Phase I of the Natural Gas Market Order Instituting Ratemaking (OIR) discussed below. At that time, the CPUC will reconcile the GIR market structure with whatever structure results from the Phase I decision of the Natural Gas Market OIR.

### Natural Gas Market OIR

The CPUC's Natural Gas Market OIR was instituted in January 2004 and will be addressed in two phases. A decision on Phase I was issued in September 2004 and Phase II is awaiting CPUC direction on further proceedings. In Phase I, the CPUC's objective was to develop a process enabling the CPUC to review and pre-approve new interstate capacity contracts before they are executed. In addition, the California Utilities must submit proposals on any liquefied natural gas (LNG) project to which interconnection is planned, providing costs and terms, including access to the pipelines in Mexico being developed by affiliated company, Sempra Pipelines & Storage. Phase II will primarily address emergency reserves and ratemaking policies. The CPUC's objective in the ratemaking policy component of Phase II is to identify and propose changes to policies that create incentives that are consistent with the goal of providing adequate and reliable long-term supplies and that do not conflict with energy efficiency programs. The focus of the Gas OIR is the period from 2006 to 2016. Since GIR, discussed above, would end in August 2006 and there is overlap between GIR and the OIR issues, a number of parties (including SoCalGas) have requested the CPUC not to implement GIR.

The California Utilities have made comprehensive filings in the OIR outlining a proposed market structure that is intended to create access to new natural gas supply sources (such as LNG, which is the business of affiliated company, Sempra LNG) for California. In their Phase I and Phase II filings, SoCalGas and SDG&E proposed a framework to provide firm tradable access rights for intrastate natural gas transportation; provide SoCalGas with continued balancing account protection for intrastate transmission and distribution revenues, thereby eliminating throughput risk; and integrate the transmission systems of SoCalGas and SDG&E so as to have common rates and rules. The California Utilities also proposed that the capital expenditures necessary to access new sources of supply be included in ratebase and that the total amount of the expenditures would be $200 million to $300 million.

The California Utilities also proposed a methodology and framework to be used by the CPUC for granting pre-approval of new interstate transportation agreements. The Phase I decision approved the California Utilities' transportation capacity pre-approval procedures with some modifications. In January 2005, SDG&E was granted pre-approval of a capacity contract with El Paso Natural Gas Company (El Paso) that would expire in 2007. All interstate transportation capacity under the pre-approved contracts will be used to transport natural gas supplies on behalf of the California Utilities' core residential and small commercial customers, and all costs of the capacity will be recovered in the customers' rates through each utility's Purchased Gas Account, a balancing account. In December 2004, pursuant to the Phase I decision, SoCalGas filed an application to implement proposals for transmission system integration, firm access rights, and off-system delivery services. The CPUC has determined that the ratemaking treatment and cost responsibility for any access-related infrastructure will be addressed in future applications to be filed when more is known about the particular projects. Phase II of the Gas Market OIR will review the CPUC’s ratemaking policies on throughput risk to better align these with its objectives of promoting energy conservation and adequate infrastructure. Phase II will also investigate the need for emergency natural gas storage reserves and the role of the utility in backstopping the noncore market.

**Cost of Service**

On December 2, 2004, the CPUC issued a decision in the California Utilities' cost of service proceedings that essentially approved a settlement recommended by most major parties to the proceedings. The decision reduces the California Utilities' annual rate revenues, effective retroactively to January 1, 2004, by an aggregate net amount of approximately $23 million from the rates in effect during 2003. The reduced rates will remain in effect through 2007, subject to annual attrition allowances. Of the reduction, $10 million relates to what SDG&E believes to be a computational error concerning its nuclear electric rate revenues. With respect to the $10 million reduction, a Petition for Modification and an Application for Rehearing were filed in December 2004 and January 2005, respectively.

Attrition allowances, performance-based incentive mechanisms (PBR), which are described in the following section, and related matters are being addressed by the CPUC in Phase II of the cost of service proceedings, expected to be decided in the first quarter of 2005. In addition to recommending changes in the PBR formulas, the CPUC's Office of Ratepayer Advocates (ORA) also proposed the possibility of performance penalties for service quality, safety and electric service reliability, without the possibility of performance awards. Hearings took place in June 2004. In July 2004, all of the active parties in Phase II who dealt with post-test-year ratemaking and performance incentives filed for adoption by the CPUC of an all-party settlement agreement for most of the Phase II issues, including annual inflation adjustments and earnings sharing. The proposed settlement does not cover performance incentives. For the interim years of 2005-2007, the Consumer Price Index would be used to adjust the escalatable authorized base rate revenues within identified floors and ceilings, each of which limits the adjustment to approximately three to five percent of the prior year's authorized base rate revenues.

SDG&E had filed for continuation of existing PBR mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but did not determine the extent of rewards or penalties. As part of the proposed Phase II Settlement Agreement, earnings sharing, under which IOUs return to customers a percentage of earnings above specified levels, would be suspended for 2004 and resume for 2005 through 2007. The proposed earnings sharing mechanism also provides the utility the option to file for suspension of the earnings sharing mechanism if earnings fall 175 basis points or more below its authorized rate of return; however, if earnings are more than 300 basis points above the utility’s authorized rate of return, the earnings sharing mechanism would be automatically suspended and trigger a formal regulatory review by the CPUC to determine whether modification of the ratemaking mechanism is required.

On February 15, 2005, the Administrative Law Judge (ALJ) and the CPUC Commissioner assigned to Phase II of the cost of service proceedings issued differing proposed decisions for consideration by the CPUC. If adopted by the CPUC, the ALJ's decision would not approve the parties' settlement of the Phase II issues, but would authorize the California Utilities to adjust their authorized revenues in each of years 2005 through 2007 on a formula basis similar to that proposed by the California Utilities and also establish performance measures with reward and penalty potentials of approximately $20 million. In addition, the ALJ's decision would have the utilities' cost of capital reviewed on an annual basis. If adopted by the CPUC, the Commissioner's proposed decision would approve the parties' settlement and also approve performance measures for customer service, safety and reliability with the same reward and penalty provisions as the ALJ's proposed decision. The Commissioner's proposed decision also would continue the use of the cost of capital adjustment mechanism currently in place, which adjusts each utility's rate of return automatically based on market indices. The CPUC may adopt either proposed decision, as proposed or with modifications, or reject both and adopt a different result.

The California Utilities had been equally sharing between ratepayers and shareholders the estimated savings for the 1998 business combination that created Sempra Energy. Pursuant to an October 2001 CPUC decision, that sharing has ceased and all merger savings go to ratepayers beginning with 2003.

**Performance-Based Regulation**

PBR consists of three primary components. The first is a mechanism to adjust rates in years between general rate cases or cost of service cases. It annually adjusts base rates from those of the prior year to provide for inflation, changes in the number of customers and efficiencies.

The second component is a mechanism whereby any earnings in excess of those authorized plus a narrow band above that are shared with customers in varying degrees depending upon the amount of the additional earnings.

The third component consists of a series of measures of utility performance. Generally, if performance is outside of a band around the specified benchmark, the utility is rewarded or penalized certain dollar amounts.

The three areas that have been eligible for PBR rewards or penalties are operational incentives based on measurements of safety, reliability and customer satisfaction; demand-side management (DSM) rewards based on the effectiveness of the programs; and natural gas procurement rewards or penalties. The CPUC is also considering a new reward/penalty related to electricity procurement, now that the utilities have resumed this activity. However, as noted under "Cost of Service," Phase II of the California Utilities' current cost of service proceeding is not complete. As a result, these safety, reliability and customer satisfaction incentive mechanisms (i.e., those that are reviewed in the Cost of Service proceeding) were not in effect during 2004. However, it is not expected that the effect would be other than a one-year moratorium of the mechanisms.

PBR and DSM rewards are not included in the company's earnings before CPUC approval is received. The only incentive reward approved during 2004 consisted of $1.5 million related to SDG&E's Year 10 natural gas PBR, which was approved in August 2004. This reward was awarded by the CPUC subject to refund based on the outcome of the Border Price Investigation discussed below. The cumulative amount of rewards subject to refund based on the outcome of the Border Price Investigation is $8.4 million, all of which has been included in net income in 2004 or previously.

On December 30, 2004, a joint settlement agreement between the California Utilities and the ORA (collectively, the joint parties) was filed with the CPUC for approval. The settlement agreement resolves all outstanding shareholder earnings claims filed with the CPUC commencing in 2000 and those claims that would have been filed through 2007 associated with DSM, energy efficiency and low-income energy efficiency programs. The proposed settlement is for $73 million (including interest, franchise fees, uncollectible amounts and awards earned in prior years that had not yet then been requested). The joint parties requested expeditious approval of the settlement agreement, without modification. A CPUC decision is expected by the end of the second quarter of 2005.

At December 31, 2004, other performance incentives were pending CPUC approval and, therefore, were not included in the company's earnings (dollars in millions):

| Program | |
|---|---|
| 2003 Distribution PBR | $ 8.2 |
| Natural gas PBR Year 11 | .2 |
| Total | $ 8.4 |

**Cost of Capital**

Effective January 1, 2005, SDG&E's authorized return on ratebase (ROR) and ROE became 8.18 percent and 10.37 percent, respectively, for its electric distribution and natural gas businesses, down from 8.77 percent and 10.9 percent, respectively. The decrease is a result of the CPUC's automatic triggering mechanism, which resets these rates whenever Moody's Aa utility bond yield as published by Mergent Bond Record changes by more than a specified amount. The current benchmark is 6.19 percent and an automatic adjustment would be triggered if the Mergent Aa utility bond yield were to average less than 5.19 percent or greater than 7.19 percent during the April - September timeframe of any year. The effect of the 2004 changes in ROR and ROE will be to decrease net income in 2005 by $10 million from what it would have been if the 2005 rates had not changed from the 2004 rates. In December 2004, the CPUC ordered SDG&E to file a cost of capital application in 2005 to take effect January 1, 2006. SDG&E had recommended that the CPUC approve a policy allowing utilities to increase the equity in their authorized capital structure to adjust for the debt equivalent effect of purchased power agreements. The CPUC has directed that such adjustment only be considered in the context of a full review of the cost of capital. The electric-transmission cost of capital is determined under a FERC proceeding and is currently at an 11.25% ROE.

Potential changes to this process are described above in "Cost of Service."

**Biennial Cost Allocation Proceeding**

The Biennial Cost Allocation Proceeding (BCAP) determines the allocation of authorized costs between customer classes for natural gas transportation service provided by the company and adjusts rates to reflect variances in sales volumes as compared to the forecasts previously used in establishing transportation rates. SDG&E filed with the CPUC its 2005 BCAP application in September 2003, requesting updated transportation rates effective January 1, 2005. In November 2003, an Assigned Commissioner Ruling stayed the BCAP application until a decision is issued in the GIR implementation proceeding. As a result of the April 1, 2004 decision on GIR implementation as described in Natural Gas Industry Restructuring above, in May 2004 the ALJ in the 2005 BCAP issued a decision dismissing the BCAP application. The company is required to file a new BCAP application after the stay in the GIR implementation proceeding is lifted.

**CPUC Investigation of Energy-Utility Holding Companies**

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. The CPUC broadly determined that it could, in appropriate circumstances, require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to provide for their utility subsidiaries' capital requirements, as the IOUs previously acknowledged in connection with their holding companies' formations. In January 2002, the CPUC ruled that it had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed.

In a May 2004 opinion, the California Court of Appeal upheld the CPUC's assertion of limited enforcement jurisdiction, but concluded that the CPUC's interpretation of the "first priority" condition (that the holding companies could be required to infuse cash into the utilities as necessary to meet the utilities' obligation to serve) was not ripe for review. In September 2004, the California Supreme Court declined to review the California Court of Appeal's decision.

**CPUC Investigation of Compliance with Affiliate Rules**

In February 2003, the CPUC opened an investigation of the business activities of SDG&E, SoCalGas and Sempra Energy to determine if they have complied with statutes and CPUC decisions in the management, oversight and operations of their companies. In September 2003, the CPUC suspended the procedural schedule until it completes an independent audit to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of SDG&E and SoCalGas. The audit, covering years 1997 through 2003, is expected to be completed by the third quarter of 2005. The scope of the audit will be broader than the annual affiliate audit. In accordance with existing CPUC requirements, the California Utilities' transactions with other Sempra Energy affiliates have been audited by an independent auditing firm each year, with results reported to the CPUC, and there have been no material adverse findings in those audits.

**Recovery of Certain Disallowed Transmission Costs**

In August 2002, the FERC issued Opinion No. 458, which effectively disallowed SDG&E's recovery in its transmission rates of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink (SWPL) under the SWPL Participation Agreements, and charges assessed to SDG&E under the California Independent System Operator (ISO) FERC tariff related to energy schedules of its SWPL co-owners. As a result, SDG&E is incurring unreimbursed costs of $4 million to $8 million per year. SDG&E has appealed the FERC decision to the Federal Court of Appeals, which has set oral argument for May 9, 2005.

SDG&E has challenged the propriety of the disallowed ISO charges in several proceedings. In July 2001, SDG&E filed an arbitration claim against the ISO, claiming the ISO should not charge SDG&E for the transmission losses attributable to its SWPL co-owners' energy schedules. In October 2003, the arbitrator awarded SDG&E all amounts claimed, which totaled $22 million, including interest, as of the time of the award. The ISO appealed this result to the FERC and decision on this appeal is pending.

SDG&E has also challenged at the FERC the ISO's grid management charges assessed on the subject SWPL schedules. In January 2004, the FERC denied rehearing of its Opinion No. 463, which upheld such charges on the subject SWPL schedules for 2001 through 2003, but ordered certain refunds to SDG&E. The refunds are pending before the FERC, as is a separate proceeding involving application of the charges to the subject schedules from 2004 forward. In addition, in March 2004, SDG&E petitioned the U.S. Court of Appeals for review of these FERC orders. The court has held SDG&E's appeal in abeyance pending the FERC's disposition of other parties' rehearing requests.

SDG&E has also commenced a private arbitration to reform the SWPL Participation Agreements to remove prospectively SDG&E's obligation to provide to its SWPL co-owners the services that result in unreimbursed ISO tariff charges. The parties have agreed to hold the arbitration in abeyance pending resolution of the related FERC proceedings.

**Southern California Wildfires**

On June 28, 2004, SDG&E filed its catastrophic event memorandum accounts (CEMA) application with the CPUC to recover incremental operating and maintenance and capital costs of its natural gas and electric distribution systems associated with the 2003 California wildfires. In that application, SDG&E is requesting a 2005 revenue requirement of $20 million, representing the operating and maintenance costs of $12 million plus the 2004 and 2005 ongoing annual amounts of $4 million to recover the $26 million of capital costs and the authorized return thereon. The company expects no significant effect on earnings from the fires. The assigned ALJ indicated that he expects to issue a proposed decision during the first quarter of 2005.

### Gain on Sale Rulemaking

A gain on sale rulemaking was issued in September 2004 in order to standardize the treatment of gains on sales of property by utilities. This rulemaking may result in the adoption of a general ratemaking policy for allocation between utility shareholders and ratepayers of any gain or loss on sale of utility property. The CPUC will consider adopting a standard percentage allocation, probably between 5 percent and 50 percent to shareholders, rather than resolving such allocations on a case-by-case basis, as is now its practice. In unusual circumstances the CPUC would be able to depart from the standard allocation to be adopted. The CPUC intends to apply this standard percentage to sales of both depreciable property and non-depreciable property. The rulemaking states that the new policy would replace the CPUC'S current policy of allocating all gain or loss to shareholders on sale to a municipality of a utility operating system. The final outcome of the rulemaking may be different than that proposed for comment in the order instituting the rulemaking. No schedule has been announced yet for this proceeding.

## NOTE 12. COMMITMENTS AND CONTINGENCIES

### Natural Gas Contracts

SDG&E buys natural gas under long-term contracts. Purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. SDG&E transports natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines that expire on various dates between 2005 and 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity, and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues its ongoing assessment of its long-term pipeline capacity portfolio, including the release of a portion of this capacity to third parties. In accordance with regulatory directives, SDG&E will reconfigure its pipeline capacity portfolio by November 2005 to secure firm transportation rights from a diverse mix of U.S. and Canadian supply sources for its projected core customer natural gas requirements.

All of SDG&E's natural gas is delivered through SoCalGas' pipelines under a short-term transportation agreement. In addition, under a separate agreement expiring in March 2006, SoCalGas provides SDG&E eight billion cubic feet of storage capacity.

At December 31, 2004, the future minimum payments under existing natural gas storage and transportation contracts were:

<table>
<caption>

(Dollars in millions)

| <s> | <c> |
|---|---|
| 2005 | $ 17 |
| 2006 | 23 |
| 2007 | 14 |
| 2008 | 14 |
| 2009 | 10 |
| Thereafter | 128 |
| Total minimum payments | $ 206 |

</table>

Total payments under natural gas contracts were $347 million in 2004, $274 million in 2003 and $205 million in 2002.

**Purchased-Power Contracts**

For 2005, SDG&E expects to receive 49 percent of its customer power requirement from DWR allocations. Of the remaining requirements, SONGS is expected to account for 21 percent, long-term contracts for 19 percent and spot market purchases for 11 percent. The contracts expire on various dates through 2032. In addition, during 2002 SDG&E entered into contracts which will provide five percent of its 2005 total energy sales from renewable sources. These contracts expire on various dates through 2025.

At December 31, 2004, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)

| | |
|---|---|
| 2005 | $ 218 |
| 2006 | 241 |
| 2007 | 274 |
| 2008 | 319 |
| 2009 | 316 |
| Thereafter | 4,017 |
| Total minimum payments | $ 5,385 |

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. Excluding DWR-allocated contracts, total payments under the contracts were $329 million in 2004, $396 million in 2003 and $235 million in 2002.

**Leases**

SDG&E has operating leases on real and personal property expiring at various dates from 2005 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2 percent to 5 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 SDG&E.

At December 31, 2004, the minimum rental commitments payable in future years under all noncancellable leases were as follows:

| (Dollars in millions) | |
|---|---|
| 2005 | $ 19 |
| 2006 | 18 |
| 2007 | 16 |
| 2008 | 10 |
| 2009 | 10 |
| Thereafter | 14 |
| Total future rental commitments | $ 87 |

Rent expense for operating leases totaled $20 million in each of 2004 and 2003 and $18 million in 2002.

**Construction Projects**

In addition to the usual expenditures for plant improvements, the company will purchase in 2006 the 550-MW Palomar power plant, which is currently being constructed by Sempra Generation, for $500 million. The company has also contracted to purchase a 45-MW generating facility being constructed by an unrelated party.

**Guarantees**

As of December 31, 2004, the company did not have any outstanding guarantees.

**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. As applicable, appropriate and relevant, these laws and regulations require that the company investigate and remediate the effects of the release or disposal of materials at sites associated with past and present operations, including sites at which the company has been identified as a Potentially Responsible Party (PRP) under the federal Superfund laws and comparable state laws. The company is required to obtain numerous governmental permits, licenses and other approvals to construct facilities and operate its businesses. Additionally, to comply with these legal requirements, it must spend significant sums on environmental monitoring, pollution control equipment and emissions fees. In addition, existing environmental regulations could be revised or reinterpreted and other new laws and regulations could be adopted or become applicable to the company and its facilities. Costs incurred to operate the facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Significant costs incurred to mitigate or prevent future environmental contamination or extend the life, increase the capacity or improve the safety or efficiency of property utilized in current operations are capitalized. The company's capital expenditures to comply with environmental laws and regulations were $9 million in 2004, $5 million in 2003 and $4 million in 2002. The cost of compliance with these regulations over the next five years is not expected to be significant.

Costs that relate to current operations or an existing condition caused by past operations are generally recorded as a regulatory asset due to the assurance that these costs will be recovered in rates.

The environmental issues currently facing the company or resolved during the last three years include investigation and remediation of its manufactured-gas sites (two completed as of December 31, 2004 and site-closure letters received), 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 PRP (investigations and remediations are continuing) and mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS (the requirements for enhanced fish protection, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands are in process).

Environmental liabilities are recorded when the company's liability is probable and the costs are reasonably estimable. In many cases, however, investigations are not yet at a stage where the company has been able to determine whether it is liable or, if the liability is probable, to reasonably estimate the amount or range of amounts of the cost or certain components thereof. Estimates of the company's liability are further subject to other uncertainties, such as the nature and extent of site contamination, evolving remediation standards and imprecise engineering evaluations. The accruals are reviewed periodically and, as investigations and remediation proceed, adjustments are made as necessary. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Not including the liability for SONGS marine mitigation, which SDG&E is participating in jointly with Edison, at December 31, 2004, the company's accrued liability for environmental matters was $11.4 million, of which $1.8 million is related to manufactured-gas sites, $8.7 million to cleanup at SDG&E's former fossil-fueled power plants and $0.9 million to waste-disposal sites used by the company (which has been identified as a PRP). These accruals are expected to be paid ratably over the next three years.

**Nuclear Insurance**

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. The insurance policy provides $300 million in coverage, which is the maximum amount available. In addition to this primary financial protection, the Price-Anderson Act provides for up to $10.5 billion of secondary financial protection if the liability loss exceeds the insurance limit. Should any of the licensed/commercial reactors in the United States experience a nuclear liability loss which exceeds the $300 million insurance limit, all utilities owning nuclear reactors could be assessed under the Price-Anderson Act to provide the secondary financial protection. SDG&E and the other co-owners of SONGS could be assessed up to $201 million under the Price-Anderson Act. SDG&E's share would be $40 million unless a default were to occur by any other SONGS owner. In the event the secondary financial protection limit were insufficient to cover the liability loss, the Price-Anderson Act provides for Congress to enact further revenue-raising measures to pay claims. These measures could include an additional assessment on all licensed reactor operators.

SDG&E and the other owners of SONGS have $2.75 billion of nuclear property, decontamination and debris removal insurance. The coverage also provides the SONGS owners up to $490 million for outage expenses/replacement power incurred because of accidental property damage. This coverage is limited to $3.5 million per week for the first 52 weeks, and $2.8 million per week for up to 110 additional weeks. There is a deductible waiting period of 12 weeks prior to receiving indemnity payments. The insurance is provided through a mutual insurance company owned by utilities with nuclear facilities. Under the policy's risk sharing arrangements, insured members are subject to retrospective premium assessments if losses at any covered facility exceed the insurance company's surplus and reinsurance funds. Should there be a retrospective premium call, SDG&E could be assessed up to $8.8 million.

Both the nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for non-certified acts (as defined by the Terrorism Risk Insurance Act) of terrorism-related SONGS losses, including replacement power costs. An industry aggregate limit of $300 million exists for liability claims, regardless of the number of non-certified acts affecting SONGS or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.24 billion exists for property claims, including replacement power costs, for non-certified acts of terrorism affecting SONGS or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these non-certified terrorist acts.

For certified acts of terrorism, the individual policy limits stated above apply.

**Legal Proceedings**

Except for the matters referred to below, neither the company nor its subsidiary are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses. At December 31, 2004, the company had accrued approximately $38 million to provide for the costs of legal proceedings related to the 2000-2001 California energy crisis. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations.

California Energy Crisis

In 2000 and 2001, California experienced a severe energy crisis characterized by dramatic increases in the prices of electricity and natural gas. The energy crisis has generated many, often duplicative, governmental investigations, regulatory proceedings and lawsuits involving numerous energy companies seeking recovery of tens of billions of dollars for allegedly unlawful activities asserted to have caused or contributed to the energy crisis. The material proceedings arising out of the energy crisis that involve the company are summarized below.

*Natural Gas Cases*

Class-action and individual antitrust and unfair competition lawsuits filed in 2000 and thereafter, and currently consolidated in San Diego Superior Court, seek damages, alleging that Sempra Energy, SoCalGas and SDG&E, along with El Paso and several of its affiliates, unlawfully sought to control natural gas and electricity markets. In December 2003, the Court approved a settlement whereby the applicable El Paso entities will pay approximately $1.6 billion to resolve these claims (including cases involving unrelated claims not applicable to Sempra Energy, SoCalGas or SDG&E). The proceeding against Sempra Energy and the California Utilities has not been settled and continues to be litigated. In October 2004, certain of the plaintiffs issued a news release asserting that they could recover as much as $24 billion from Sempra Energy and the California Utilities if their allegations were upheld at trial. During the third quarter of 2004, the court denied motions for summary judgment in favor of Sempra Energy and the California Utilities. The Court of Appeal has declined to review the summary judgment denial and the companies have petitioned for review by the California Supreme Court. Interim review pending a final decision on the merits of the case is entirely at the discretion of the California Supreme Court. On January 18, 2005, the judge stated that pre-trial motions will be heard on June 3, 2005, and set a trial date of September 2, 2005.

Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada, alleging that El Paso and certain Sempra Energy subsidiaries unlawfully sought to control the natural gas market in their respective states. The claims against the Sempra Energy defendants in the Arizona lawsuit were settled in September 2004 for $150,000 and have been dismissed with prejudice. The Nevada Attorney General’s lawsuit remains pending.

The company is cooperating with an investigation being conducted by the California Attorney General into possible anti-competitive behavior in the natural gas and electricity markets during the 2000-2001 energy crisis. In December 2004, several of the company's senior officers testified at investigational hearings conducted by the California Attorney General's Office. The company expects additional hearings to take place in early 2005.

In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, and included Sempra Energy, the California Utilities and other company subsidiaries, seeking recovery of damages alleged to aggregate in excess of $150 million (before trebling) from an alleged conspiracy to drive up or control natural gas prices, eliminate competition and increase market volatility, breach of contract and wire fraud. On January 27, 2004, the U.S. District Court dismissed the Sierra Pacific Resources case against all of the defendants, determining that this is a matter for the FERC to resolve. However, the court granted plaintiffs' request to amend their complaint. Sempra Energy filed another motion to dismiss on plaintiffs' amended complaint. After argument on November 29, 2004, the federal court dismissed the Sierra Pacific case with prejudice. Plaintiffs have filed a notice of appeal with the Ninth Circuit Court of Appeals.

In July 2004, the City and County of San Francisco, the County of Santa Clara and the County of San Diego brought actions, alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications and by entering into wash trades and by engaging in "churning" transactions with Reliant Energy, in San Diego Superior Court against various entities, including Sempra Energy, Sempra Commodities, SoCalGas and SDG&E.

*Electricity Cases*

Various antitrust lawsuits, which seek class-action certification, allege that numerous entities, including Sempra Energy and certain subsidiaries, including SDG&E, that participated in the wholesale electricity markets unlawfully manipulated those markets. Collectively, these lawsuits allege damages against all defendants in an aggregate amount in excess of $16 billion (before trebling). In January 2003, the federal court granted a motion to dismiss one of these lawsuits, filed by the Snohomish County, Washington Public Utility District, on the grounds that the claims contained in the complaint were subject to the filed rate doctrine and were preempted by the Federal Power Act. That ruling was appealed to the Ninth Circuit U.S. Court of Appeals.

CPUC Border Price Investigation

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California - Arizona border between March 2000 and May 2001. The California Utilities are the parties to the first phase of the investigation. If the investigation were to determine that the conduct of either of the California Utilities contributed to the natural gas price spikes that occurred during the investigation period, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. At December 31, 2004, the cumulative amount of shareholder awards, all of which has been included in net income, was $8.4 million.

On November 16, 2004, the CPUC ALJ assigned to the investigation issued a proposed decision for consideration by the full CPUC in the first phase of the investigation that did not include any adverse findings or make any adverse recommendations regarding SDG&E.

The CPUC may hold additional rounds of hearings to consider whether other companies, including other California utilities, contributed to the natural gas price spikes. No hearings have yet been scheduled.

FERC Refund Proceedings

The FERC is investigating prices charged to buyers in the California Power Exchange (PX) and ISO markets by various electric suppliers. The FERC is seeking to determine the extent to which individual sellers have yet to be paid for power supplied during the period of October 2, 2000 through June 20, 2001 and to estimate the amounts by which individual buyers and sellers paid and were paid in excess of competitive market prices. Based on these estimates, the FERC could find that individual net buyers, such as SDG&E, are entitled to refunds and individual net sellers are required to provide refunds. To the extent any such refunds are actually realized by SDG&E, they would be refunded to ratepayers.

In December 2002, a FERC ALJ issued preliminary findings indicating that the California PX and ISO owe power suppliers $1.2 billion for the

October 2, 2000 through June 20, 2001 period (the $3.0 billion that the California PX and ISO still owe energy companies less $1.8 billion that the energy companies charged California customers in excess of the preliminarily determined competitive market clearing prices). On March 26, 2003, the FERC adopted its ALJ's findings, but changed the calculation of the refund by basing it on a different estimate of natural gas prices. The March 26 order estimates that the replacement formula for estimating natural gas prices will increase the refund obligations from $1.8 billion to more than $3 billion for the same time period. Pending in the Ninth Circuit are various parties' appeals on aspects of the FERC's order.

In a series of orders in 2004, the FERC has provided further direction and clarifications regarding the methodology to be used by the ISO and PX to recalculate the precise refund obligations and entitlements through their settlement models.

FERC Manipulation Investigation

The FERC is separately investigating whether there was manipulation of short-term energy markets in the western United States that would constitute violations of applicable tariffs and warrant disgorgement of associated profits. In this proceeding, the FERC's authority is not confined to the periods relevant to the refund proceeding. In May 2002, the FERC ordered all energy companies engaged in electric energy trading activities to state whether they had engaged in various specific trading activities (generally described as manipulating or "gaming" the California energy markets) in violation of the PX and ISO tariffs.

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. The FERC directed 43 entities, including SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. SDG&E and the FERC resolved the matter through a settlement, which documents the ISO's finding that SDG&E did not engage in market activities in violation of the ISO or PX tariffs, and in which SDG&E agreed to pay $27,792 into a FERC-established fund.

On June 25, 2003, the FERC determined that it was appropriate to initiate an investigation into possible physical and economic withholding in the California ISO and PX markets. On August 1, 2003, the FERC staff issued an initial report that determined there was no need to further investigate particular entities for physical withholding of generation. For the purpose of investigating economic withholding, SDG&E received data requests from the FERC staff and provided responses. In May 2004, based on the results of its investigation, the FERC's Office of Market Oversight and Investigation informed SDG&E that its bidding procedures are no longer being investigated by the FERC.

Settlement of Claims Associated with the FERC's Investigations

During 2004, three settlements of claims associated with the FERC's investigations were announced. One settlement, in which SDG&E received a net payment of $11.6 million in August 2004, resolves all but a few claims against The Williams Companies and Williams Power Company for the period May 1, 2000 through June 20, 2001. Another settlement, in which SDG&E received a net payment of $13.5 million (of the $13.8 million total SDG&E settlement allocation) in November 2004, resolves all claims against Dynegy, NRG Energy and West Coast Power LLC for the period January 1, 2000 through June 20, 2001. A third settlement, in which SDG&E received a net payment of $14.4 million (of the $14.7 million total SDG&E settlement allocation) in January 2005, resolves specified claims against Duke Energy for the period January 1, 2000 though June 20, 2001. On January 13, 2005, SDG&E announced a $23.8 million settlement (including an unsecured claim in the Mirant bankruptcy proceeding valued at approximately $2.4 million), which resolves specified claims against merchant generator Mirant Corp. for the 2000-2001 energy crisis period. The settlement is pending final CPUC, FERC and U.S. Bankruptcy Court (for Mirant) approval. In all cases, the majority of the funds was received within 20 days of receiving FERC approval with the remainder contingent on certain actions by the FERC, the ISO and the PX. Receipt of the remaining amounts by SDG&E would take place at the conclusion of the FERC refund proceeding, now expected to be in early 2006. These funds would be received for the benefit of SDG&E's bundled customers and will reimburse SDG&E for the costs of litigating this matter. In November 2004, the CPUC approved SDG&E's proposal to apply 70 percent (about $17 million) of the refunds due to ratepayers to the AB 265 undercollection, thus facilitating the full recovery of the undercollections, as further discussed in Note 10.

Other Litigation

The Utility Consumers' Action Network (UCAN), a consumer-advocacy group which had requested a CPUC rehearing of a CPUC decision concerning the allocation of certain power contract gains between SDG&E customers and the company, appealed the CPUC's rehearing denial to the California Court of Appeal. On July 12, 2004, the Court of Appeal affirmed the CPUC's decision. On August 20, 2004, UCAN filed a Petition for Review in the California Supreme Court. On November 10, 2004, the Supreme Court denied review.

**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. This delay by the DOE will lead to increased cost for spent fuel storage. This cost will be recovered through SONGS revenue unless the company is able to recover the increased cost from the federal government.

**Electric Distribution System Conversion**

Under a CPUC-mandated program, the cost of which is included in utility rates, 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, 2004, the aggregate unexpended amount of this commitment was $80 million. Capital expenditures for underground conversions were $23 million in 2004, $28 million in 2003 and $33 million in 2002.

**Concentration Of Credit Risk**

The company maintains credit policies and systems to manage overall credit risk. These policies include 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. The company grants credit to customers and counterparties, substantially all of whom are located in its service territories, which covers all of San Diego County and an adjacent portion of Orange County.

**NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)**

<table>
<caption>

| (Dollars in millions) | Quarters ended<br>March 31 | June 30 | September 30 | December 31 |
|---|---|---|---|---|
| <S> | <C> | <C> | <C> | <C> |
| 2004 | | | | |
| Operating revenues | $ 580 | $ 536 | $ 550 | $ 608 |
| Operating expenses | 518 | 488 | 486 | 531 |
| Operating income | $ 62 | $ 48 | $ 64 | $ 77 |
| Net income | $ 51 | $ 31 | $ 62 | $ 69 |
| Dividends on preferred stock | 1 | 1 | 2 | 1 |
| Earnings applicable to common shares | $ 50 | $ 30 | $ 60 | $ 68 |
| 2003 | | | | |
| Operating revenues | $ 562 | $ 520 | $ 667 | $ 562 |
| Operating expenses | 497 | 467 | 533 | 433 |
| Operating income | $ 65 | $ 53 | $ 134 | $ 129 |
| Net income | $ 47 | $ 42 | $ 121 | $ 130 |
| Dividends on preferred stock | 2 | 1 | 1 | 2 |
| Earnings applicable to common shares | $ 45 | $ 41 | $ 120 | $ 128 |

</table>

Operating revenues and expenses in the fourth quarter of 2004 include the favorable impact of the final cost of service decision and operating expenses include litigation costs recorded in the fourth quarter.

Operating revenues in the third quarter of 2003 included the recognition of $116 million before-tax related to the approved settlement of intermediate-term purchase power contracts. The after-tax impact to net income was $65 million. Additionally, operating expenses in the third quarter of 2003 were impacted by a $19 million before-tax charge for litigation. The after-tax impact was $11 million. Net income in the fourth quarter of 2003 includes $79 million related to the favorable resolution of income tax issues.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of San Diego Gas & Electric Company:

We have audited the accompanying consolidated balance sheets of San Diego Gas & Electric Company and subsidiary (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (United States). 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 the Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company’s internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2005 expressed an unqualified opinion on management’s assessment of the effectiveness of the Company’s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 22, 2005

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of San Diego Gas & Electric Company:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that San Diego Gas & Electric and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004 of the Company and our report dated February 22, 2005 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of a new accounting standard.

/s/ *DELOITTE & TOUCHE LLP*

San Diego, California
February 22, 2005

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

None.

**ITEM 9A. CONTROLS AND PROCEDURES**

**Evaluation of Disclosure Controls and Procedures** – Management has established disclosure controls and procedures to ensure that material information relating to the company and its consolidated subsidiaries is made known to the officers who certify the company's financial reports and to other members of senior management and the Board of Directors. In designing and evaluating these controls and procedures, management recognizes that any system of controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired objectives and necessarily applies judgment in evaluating the cost-benefit relationship of other possible controls and procedures.

Based on their evaluation as of December 31, 2004, the principal executive officer and principal financial officer of the company have concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) are effective, at the reasonable assurance level, to ensure that the information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by SEC rules and forms.

**Management's Report on Internal Control Over Financial Reporting** - Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of company management, including the principal executive officer and principal financial officer, the company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the company's evaluation under the framework in *Internal Control – Integrated Framework*, management concluded that the company's internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in its report, which is included herein.

**ITEM 9B. OTHER INFORMATION**

In February, 2005, Sempra Energy entered into a severance pay agreement with each executive officer of SDG&E to replace the previously reported similar agreements. The agreements are for an initial term of three years and are subject to automatic one year extensions on each anniversary of the effective date (commencing with the second anniversary) unless Sempra Energy or the executive elects not to extend the term.

The agreements provide severance benefits to the executive in the event that Sempra Energy or its subsidiaries terminates the executive's employment (other than for cause, death or disability) or the executive does so for good reason.

Severance benefits under the agreements vary with the executive's position and include (i) a lump sum cash severance payment varying from 50% to 100% of the sum of the executive's annual base salary plus the greater of the executive's average annual bonus or average annual target bonus for the two years prior to termination; (ii) continuation of health insurance benefits for a period varying from six months to one year; and (iii) financial planning and outplacement services for a period varying from 18 months to two years. If the termination were to occur within two years after a change in control of the company, (i) the lump sum cash severance payment would be multiplied by two; (ii) an additional lump sum payment would be paid equal to the pro rata portion for the year of termination of the target amount payable under any annual incentive compensation award for that year or, if greater, the average of the three highest gross annual bonus awards paid to the executive in the five years preceding the year of termination; (iii) all equity-based incentive compensation awards would immediately vest and become exercisable or payable and any restrictions on the awards would automatically lapse; (iv) a lump sum cash payment would be made equal to the present value of the executive's benefits under supplemental executive retirement plans calculated on the basis of the greater of actual years of service or years of service that would have been completed upon attaining age 62 and applying certain early retirement factors; (v) life, disability, accident and health insurance benefits would be continued for a period varying from one year to two years; and (vi) financial planning and outplacement services would be provided for a period varying from two years to three years.

The agreements also provide that if the terminated executive agrees to provide consulting services for two years and abide by certain covenants regarding non-solicitation of employees and information confidentiality, the executive would receive (i) an additional lump sum payment equal to the executive's annual base salary and the greater of the executive's target bonus for the year of termination or the average of the two or three highest gross annual bonus awards paid to the executive in the five years prior to termination and (ii) health insurance benefits would be continued for an additional one year.

The agreements also provide for a gross-up payment to offset the effects of any excise tax imposed on the executive under Section 4999 of the Internal Revenue Code.

Good reason is defined in the agreements to include the assignment to the executive of duties materially inconsistent with those appropriate to a senior executive of Sempra Energy and its subsidiaries; a material reduction in the executive's overall standing and responsibilities within Sempra Energy and its subsidiaries; and a material reduction in the executive's annualized compensation and benefit opportunities other than across-the-board reductions affecting all similarly situated executives of comparable rank. Following a change in control, good reason is defined to include an adverse change in the executive's title, authority, duties, responsibilities or reporting lines; reduction in the executive's annualized compensation opportunities other than across-the-board reductions of less than 10% similarly affecting all similarly situation executives of comparable rank; relocation of the executive's principal place of employment by more than 30 miles; and a substantial increase in business travel obligations. A change in control is defined to include the acquisition by one person or group of 20% or more of the voting power of Sempra Energy's shares; the election of a new majority of the board of Sempra Energy comprised of individuals who are not recommended for election by two-thirds of the current directors or successors to the current directors who were so recommended for election; certain mergers, consolidations or sales of assets that result in the shareholders of Sempra Energy owning less than 60% of the voting power of Sempra Energy or of the surviving entity or its parent; and approval by shareholders of the liquidation or dissolution of the company.

## 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 Information Statement prepared for the May 2005 annual meeting of shareholders. The information required on the company's executive officers is provided below.

**EXECUTIVE OFFICERS OF THE REGISTRANT**

| Name | Age* | Position |
|---|---|---|
| Edwin A. Guiles | 55 | Chairman and Chief Executive Officer |
| Debra L. Reed | 48 | President and Chief Operating Officer |
| James P. Avery | 48 | Senior Vice President, Electric Transmission |
| Steven D. Davis | 48 | Senior Vice President, External Relations and Chief Financial Officer |
| Margot A. Kyd | 51 | Senior Vice President, Corporate Business Solutions |
| William L. Reed | 52 | Senior Vice President, Regulatory and Strategic Planning |
| Anne S. Smith | 51 | Senior Vice President, Customer Service |
| Lee M. Stewart | 59 | Senior Vice President, Gas Transmission |
| Terry M. Fleskes | 48 | Vice President and Controller |

* As of December 31, 2004.

Except for Mr. Avery, each executive officer of San Diego Gas & Electric Company holds the same position at Southern California Gas Company and has been an officer or employee of Sempra Energy or one of its subsidiaries for more than five years. Prior to joining SDG&E in 2001, Mr. Avery was a consultant with R.J. Rudden Associates.

**ITEM 11. EXECUTIVE COMPENSATION**

The information required by Item 11 is incorporated by reference from "Election of Directors" and "Executive Compensation" in the Information Statement prepared for the May 2005 annual meeting of shareholders.

**ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS**

The security ownership information required by Item 12 is incorporated by reference from "Share Ownership" in the Information Statement prepared for the May 2005 annual meeting of shareholders.

**ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS**

None.

**ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES**

Information regarding principal accountant fees and services as required by Item 14 is incorporated by reference from "Proposal 3: Ratification of Independent Auditors" in the Information Statement prepared for the May 2005 annual meeting of shareholders.

**PART IV**

**ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K**

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

**1. Financial statements**



**2. Financial statement schedules**

Other schedules for which provision is made in Regulation S-X are not required under the instructions contained therein, are inapplicable or the information is included in the Consolidated Financial Statements and notes thereto.

### 3. Exhibits

See Exhibit Index on page 90 of this report.

### (b) Reports on Form 8-K

The following reports on Form 8-K were filed after September 30, 2004:

Current Report on Form 8-K filed October 27, 2004, discussing the current status of the California Utilities' Cost of Service Proceedings and the Border Price Investigation.

Current Report on Form 8-K filed November 4, 2004, filing as an exhibit Sempra Energy’s press release of November 4, 2004, giving the financial results for the quarter ended September 30, 2004.

Current Report on Form 8-K filed November 5, 2004, discussing the current status of the California Utilities' Cost of Service Proceedings, including a proposed decision and an alternate proposed decision issued by CPUC commissioners on November 4, 2004.

Current Report on Form 8-K filed November 17, 2004, discussing the current status of the Border Price Investigation, including the proposed decision issued by the CPUC Administrative Law Judge on November 16, 2004.

Current Report on Form 8-K filed December 3, 2004, discussing the current status of the California Utilities' Cost of Service Proceedings, including the CPUC decision issued on December 2, 2004.

Current Report on Form 8-K filed December 7, 2004, discussing and filing as an exhibit the 2005 Deferred Compensation Plan.

Current Report on Form 8-K filed January 11, 2005, discussing the current status of energy crisis litigation.

Current Report on Form 8-K filed January 18, 2005, discussing the current status of energy crisis litigation.

Current Report on Form 8-K filed February 23, 2005, filing as an exhibit Sempra Energy's press release of February 23, 2005, giving the financial results for the three months ended December 31, 2004.

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of San Diego Gas & Electric Company:

We consent to the incorporation by reference in Registration Statement Numbers 33-45599, 33-52834, 333-52150 and 33-49837 on Form S-3 of our reports dated February 22, 2005 (which reports express an unqualified opinion and include an explanatory paragraph relating to the Company’s adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement* Obligations, effective January 1, 2003) relating to the financial statements of San Diego Gas and Electric Company and management’s report on the effectiveness of internal control over financial reporting, incorporated by reference in this Annual Report on Form 10-K of San Diego Gas and Electric Company for the year ended December 31, 2004.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 22, 2005

## 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.

SAN DIEGO GAS & ELECTRIC COMPANY

By: /s/ Edwin A. Guiles
Edwin A. Guiles
Chairman and Chief Executive Officer

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.

<table>
<caption>

| **Name/Title** | **Signature** | **Date** |
|---|---|---|
| <s> | <c> | <c> |
| **Principal Executive Officer:** | | |
| Edwin A. Guiles<br>Chairman and<br>Chief Executive Officer | /s/ Edwin A. Guiles | February 23, 2005 |
| **Principal Financial Officer:** | | |
| Steven D. Davis<br>Sr. Vice President,<br>External Relations and<br>Chief Financial Officer | /s/ Steven D. Davis | February 23, 2005 |
| **Principal Accounting Officer:** | | |
| Terry M. Fleskes<br>Vice President and<br>Controller | /s/ Terry M. Fleskes | February 23, 2005 |
| **Directors:** | | |
| Edwin A. Guiles, Chairman | /s/ Edwin A. Guiles | February 23, 2005 |
| Debra L. Reed, Director | /s/ Debra L. Reed | February 23, 2005 |
| Frank H. Ault, Director | /s/ Frank H. Ault | February 23, 2005 |

</table>

**EXHIBIT INDEX**

The Forms 8-K, 10-K and 10-Q referred to herein were filed under Commission File Number 1-3779 (SDG&E), Commission File Number 1-11439 (Enova Corporation), Commission File Number 1-14201 (Sempra Energy) and/or Commission File Number 333-30761, (SDG&E Funding LLC).

**Exhibit 1 -- Underwriting Agreements**

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**

3.01 Restated Bylaws of San Diego Gas & Electric as of November 6, 2001 (2001 Form 10-K Exhibit 3.01).

**Articles of Incorporation**

3.02 Amended and Restated Articles of Incorporation of San Diego Gas & Electric Company (Incorporated by reference from the SDG&E Form 10-Q for the three months ended March 31, 1994 (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.

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).

4.07 Forty-Ninth Supplemental Indenture dated June 1, 2004 (2004 Sempra Energy Form 10-K, Exhibit 4.07).

**Exhibit 10 -- Material Contracts**

10.01 Operating Agreement between San Diego Gas & Electric and the California Department of Water Resources dated April 17, 2003 (2003 Sempra Energy Form 10-K, Exhibit 10.06).

10.02 Servicing Agreement between San Diego Gas & Electric and the California Department of Water Resources dated December 19, 2002 (2003 Sempra Energy Form 10-K, Exhibit 10.07).

10.03 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).

10.04 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).

10.05 Lease agreement dated as of March 25, 1992 with CarrAmerica Development and Construction as lessor of an office complex at Century Park (1994 SDG&E Form 10-K, Exhibit 10.70).

**Compensation**

10.06 Form of Severance Pay Agreement (2004 Sempra Energy 10-K, Exhibit 10.10).

10.07 Sempra Energy 2005 Deferred Compensation Plan (San Diego Gas & Electric Form 8-K filed on December 07, 2004, Exhibit 10.1).

10.08 Sempra Energy Employee Stock Incentive Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.1).

10.09 Sempra Energy Amended and Restated Executive Life Insurance Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.2).

10.10 Sempra Energy Excess Cash Balance Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.3).

10.11 Form of Sempra Energy 1998 Long Term Incentive Plan Performance-Based Restricted Stock Award (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.4).

10.12 Form of Sempra Energy 1998 Long Term Incentive Plan Nonqualified Stock Option Agreement (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.5).

10.13 Form of Sempra Energy 1998 Non-Employee Directors' Stock Plan Nonqualified Stock Option Agreement (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.6).

10.14 Sempra Energy Supplemental Executive Retirement Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.7).

10.15 Neal Schmale Restricted Stock Award Agreement (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.8).

10.16 Severance Pay Agreement between Sempra Energy and

Donald E. Felsinger (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.9).

10.17 Severance Pay Agreement between Sempra Energy and Neal Schmale (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.10).

10.18 Sempra Energy Executive Personal Financial Planning Program Policy Document (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.11).

10.19 2003 Sempra Energy Executive Incentive Plan B (2003 Sempra Energy Form 10-K, Exhibit 10.10).

10.20 Sempra Energy 2003 Executive Incentive Plan (June 30, 2003 Sempra Energy Form 10-Q Exhibit 10.1).

10.21 Amended 1998 Long-Term Incentive Plan (June 30, 2003 Sempra Energy Form 10-Q Exhibit 10.2).

10.22 Sempra Energy Executive Incentive Plan effective January 1, 2003 (2002 Sempra Energy Form 10-K, Exhibit 10.09).

10.23 Amended Sempra Energy Retirement Plan for Directors (2002 Sempra Energy Form 10-K, Exhibit 10.10).

10.24 Amended and Restated Sempra Energy Deferred Compensation and Excess Savings Plan (September 30, 2002 Sempra Energy Form 10-Q, Exhibit 10.3).

10.25 Form of Sempra Energy Severance Pay Agreement for Executives (2001 Sempra Energy Form 10-K, Exhibit 10.07).

10.26 Sempra Energy Executive Security Bonus Plan effective January 1, 2001 (2001 Sempra Energy Form 10-K, Exhibit 10.08).

10.27 Sempra Energy Deferred Compensation and Excess Savings Plan effective January 1, 2000 (2000 Sempra Energy Form 10-K, Exhibit 10.07).

10.28 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).

**Financing**

10.29 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 (1997 Enova Form 10-K, Exhibit 10.34).

10.30 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 (1996 Form 10-K, Exhibit 10.31).

10.31 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 (1996 Form 10-K, Exhibit 10.32).

10.32 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).

10.33 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).

10.34 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).

10.35 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 (1996 Form 10-K, Exhibit 10.41).

10.36 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).

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

10.38 Loan agreement with the City of Chula Vista in connection with the issuance of $251.3 million of Industrial Development Revenue Refunding Bonds, dated as of June 1, 2004 (2004 Sempra Energy Form 10-K, Exhibit 10.43).

**Nuclear**

10.39 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).

10.40 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.39 herein)(1994 SDG&E Form 10-K, Exhibit 10.56).

10.41 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 10.39 herein)(1994 SDG&E Form 10-K, Exhibit 10.57).

10.42 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 10.39 herein)(1996 Form 10-K, Exhibit 10.59).

10.43 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 10.39 herein)(1996 Form 10-K, Exhibit 10.60).

10.44 Fifth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.39 herein)(1999 Form 10-K, Exhibit 10.26).

10.45 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 10.39 herein)(1999 Form 10-K, Exhibit 10.27).

10.46 Seventh Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.39 herein)(2003 Sempra Energy Form 10-K, Exhibit 10.42).

10.47 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).

10.48 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 10.47 herein)(1996 Form 10-K, Exhibit 10.62).

10.49 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 10.47 herein)(1996 Form 10-K, Exhibit 10.63).

10.50 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 10.47 herein)(1999 Form 10-K, Exhibit 10.31).

10.51 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 10.47 herein)(1999 Form 10-K, Exhibit 10.32).

10.52 Fifth 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 10.47 herein)(2003 Sempra Energy Form 10-K, Exhibit 10.48).

10.53 Second Amended San Onofre Operating 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).

10.54 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).

**Natural Gas Transportation and Storage**

10.55 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).

10.56 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).

10.57 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).

**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, 2004, 2003, 2002, 2001 and 2000.

**Exhibit 21 -- Subsidiaries**

21.01 Schedule of Subsidiaries at December 31, 2004.

**Exhibit 23 –- Consent of Independent Registered Public Accounting Firm**, page 88.

**Exhibit 31 -- Section 302 Certifications**

31.1 Statement of Registrant's Chief Executive Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

31.2 Statement of Registrant's Chief Financial Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

**Exhibit 32 -- Section 906 Certifications**

32.1 Statement of Registrant's Chief Executive Officer pursuant to 18 U.S.C. Sec. 1350.

32.2 Statement of Registrant's Chief Financial Officer pursuant to 18 U.S.C. Sec. 1350.

**GLOSSARY**

| | |
|---|---|
| AB | California Assembly Bill |
| AFUDC | Allowance for Funds Used During Construction |
| ALJ | Administrative Law Judge |
| ARB | Accounting Research Bulletin |
| BCAP | Biennial Cost Allocation Proceeding |
| California Utilities | San Diego Gas & Electric and Southern California Gas Company |
| CEC | California Energy Commission |
| CEMA | Catastrophic Event Memorandum Act |
| CPUC | California Public Utilities Commission |
| DOE | Department of Energy |
| DSM | Demand Side Management |
| DTSC | Department of Toxic Substance Control |
| DWR | Department of Water Resources |
| Edison | Southern California Edison Company |
| El Paso | El Paso Natural Gas Company |
| EMFs | Electric and Magnetic Fields |
| ERMG | Energy Risk Management |
| ERMOC | Energy Risk management Oversight Committee |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| FSP | FASB Staff Position |
| GIR | Gas Industry Restructuring |
| ICIP | Incremental Cost Incentive Mechanism |
| IOUs | Investor-Owned Utilities |
| IRS | Internal Revenue Service |
| ISFSI | Independent Spent Fuel Storage Facility |
| ISO | Independent System Operator |
| kV | Kilovolt |
| LIFO | Last in first out inventory costing method |

| | |
|---|---|
| LNG | Liquefied Natural Gas |
| MGP | Manufactured-Gas Plants |
| mmbtu | Million British Thermal Units (of natural gas) |
| MW | Megawatt |
| NRC | Nuclear Regulatory Commission |
| OIR | Order Instituting Ratemaking |
| ORA | Office of Ratepayers Advocates |
| PBR | Performance-Based Ratemaking/Regulation |
| PG&E | Pacific Gas and Electric Company |
| PGE | Portland General Electric Company |
| PIER | Public Interest Energy Research |
| PRP | Potentially Responsible Party |
| PX | Power Exchange |
| QF | Qualifying Facility |
| RD&D | Research Development and Demonstration |
| ROE | Return on Equity |
| ROR | Return on Ratebase |
| SDG&E | San Diego Gas & Electric Company |
| SFAS | Statement of Financial Accounting Standards |
| SoCalGas | Southern California Gas Company |
| SONGS | San Onofre Nuclear Generating Station |
| SWPL | Southwest Powerlink  A transmission line connecting San Diego to Phoenix and intermediate points. |
| UCAN | Utility Consumers Action Network |
| VaR | Value at Risk |
| VIE | Variable Interest Entity |