UNITED STATES
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, 2007

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______ to ______

Commission file number 1-3779

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

California	95-1184800
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

8326 Century Park Court, San Diego, California 92123
(Address of principal executive offices)
(Zip Code)

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

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

Title of each class	Name of each exchange on which registered
Preference Stock (Cumulative) Without Par Value (except $1.70 and $1.7625 Series)	American
Cumulative Preferred Stock, $20 Par Value (except 4.60% Series)	American

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ______ No __X__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ____________ No ____X____

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 (or for such shorter period that the registrant was required to file such reports), 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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [X]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ____________ No ____X____

Exhibit Index on page 91. Glossary on page 95.

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2007 was $0.

Registrant’s common stock outstanding as of January 31, 2008, was wholly owned by Enova Corporation.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Information Statement prepared for the June 2008 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, 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 electric power, natural gas and liquefied 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; the resolution of litigation; 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 AND RISK FACTORS

Description of Business

A description of San Diego Gas & Electric Company (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, its sole subsidiary, SDG&E Funding LLC, and a variable interest entity of which it is the primary beneficiary. 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 Sempra Utilities."

Company Website

The company's website address is http://www.sdge.com and Sempra Energy’s website address is http://www.sempra.com. 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 the company. These risk factors could affect the actual results of the company and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of the company. 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, the company'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 the company 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, capital structure, rates of return, rates of depreciation, the uniform systems of accounts and long-term resource procurement. The CPUC conducts various reviews of utility performance (which may include reasonableness and prudency reviews of capital expenditures, natural gas and electricity procurement, and other costs, and reviews and audits of the company's records) 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 and performance-based regulation are discussed in Notes 10 and 11 of the Notes to Consolidated Financial

Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

The company may expend funds prior to receiving regulatory approval to proceed with a major capital project. If the project does not receive regulatory approval or management decides not to proceed with the project, the company may not be able to recover the amount expended for that project.

Periodically, SDG&E's rates are approved by the CPUC based on authorized capital expenditures and operating costs. If the company's actual capital expenditures and operating costs were to exceed the amount approved by the CPUC, it could adversely affect earnings and cash flows.

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

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

The company may be adversely affected 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 the company operates, could affect its ability to recover various costs through rates or adjustment mechanisms, or could require the company to incur additional expenses.

The construction and expansion of the company’s electric transmission and distribution facilities and natural gas pipelines require numerous permits and approvals from federal, state and local governmental agencies. If there are delays in obtaining required approvals, or if the company fails to obtain or maintain required approvals or to comply with applicable laws or regulations, its business, cash flows, results of operations and financial condition could be materially adversely affected.

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

SDG&E has a 20-percent ownership interest in the San Onofre Nuclear Generating Station (SONGS), a 2,150-megawatt (MW) nuclear generating facility near San Clemente, California. The Nuclear Regulatory Commission (NRC) 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 Sempra Utilities' future results of operations, financial condition and cash flows may be materially adversely affected by the outcome of pending litigation against them.

Sempra Energy and the Sempra Utilities are defendants in numerous lawsuits. They have expended and continue to expend substantial amounts defending these lawsuits and in connection with related investigations and regulatory proceedings and have established reserves that they believe to be appropriate for their ultimate resolution. However, uncertainties inherent in complex legal proceedings make it difficult to estimate with any degree of certainty the costs and effects of resolving legal matters. Accordingly, costs ultimately incurred may differ materially from estimated costs and could materially adversely affect Sempra Energy's and the Sempra Utilities' business, cash flows, results of operations and financial condition.

These proceedings are discussed in Note 12 of the Notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

Future environmental compliance costs could adversely affect SDG&E's profitability.

SDG&E is subject to extensive federal, state and local statutes, rules and regulations relating to environmental protection, including, in particular, global warming and greenhouse gas (GHG) emissions. It is required to obtain numerous governmental permits, licenses and other approvals to construct and operate its business. The company also is generally responsible for all on-site liabilities associated with the environmental condition of its electric generation facilities and other energy projects, regardless of when the liabilities arose and whether they are known or unknown. If SDG&E fails to comply with applicable environmental laws, it may be subject to penalties, fines and/or curtailments of its operations.

The scope and effect of new environmental laws and regulations, including their effects on current operations and future expansions, are difficult to predict. Increasing international, national, regional and state-level concerns as well as new or proposed legislation and regulation may have substantial effects on operations, operating costs, and the scope and economics of proposed expansion. In particular, state-level laws and regulations as well as proposed national and international legislation and regulation relating to GHG emissions (including carbon dioxide, methane, nitrogen oxide, hydrofluorocarbon, perfluorocarbon and sulfur hexafluoride) may limit or otherwise adversely affect the operations of the company. The company may be affected if costs are not recoverable in rates and because the effects of significantly tougher standards may cause rates to increase to levels that substantially reduce customer demand and growth. In addition, the company may be subject to penalties if certain mandated renewable energy goals are not met. Further discussion of these matters is provided in Notes 10 and 12 of the Notes to Consolidated Financial Statements herein.

In addition, existing and future laws and regulation on mercury, nitrogen and sulfur oxides, particulates or other emissions could result in requirements for additional pollution control equipment or emission fees and taxes that could adversely affect the company. Moreover, existing rules and regulations may be interpreted or revised in ways that may adversely affect the company and its facilities and operations. Additional information on these matters is provided in Note 10 of the Notes to the Consolidated Financial Statements herein.

Natural disasters, catastrophic accidents or acts of terrorism could materially adversely affect the company's business, earnings and cash flows.

Like other major industrial facilities, the company's generation facilities, electric transmission and distribution 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 the company's financial condition, 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.

The company's cash flows, ability to pay dividends and ability to meet its debt obligations largely depend on the performance of its utility operations.

The company's utility operations are the major source of liquidity. The company's ability to pay dividends on its preferred stock and meet its debt obligations is largely dependent on the sufficiency of utility earnings and cash flows in excess of operational needs.

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, rates of return, capital structure, rates of depreciation, uniform systems of accounts and long-term resource procurement, except as described below under "United States Utility Regulation." The CPUC also has jurisdiction over the proposed construction of major new electric transmission, electric distribution and natural gas transmission and distribution facilities. The CPUC conducts various reviews of utility performance, conducts audits for compliance with regulatory guidelines, and conducts investigations into various matters, such as deregulation, competition and the environment, to determine its future policies. The CPUC also regulates the interactions and transactions of the Sempra Utilities with Sempra Energy and its affiliates. Further discussion is provided in Note 11 of the Notes to Consolidated Financial Statements herein.

The California Energy Commission (CEC) establishes 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 statewide 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.

California Assembly Bill 32, the California Global Warming Solutions Act of 2006, makes the California Air Resources Board (CARB) responsible for monitoring and reducing GHG emissions. The bill requires CARB to develop and adopt a comprehensive plan for achieving real, quantifiable and cost-effective GHG emission reductions including, among other things, a statewide GHG emissions cap, mandatory reporting rules, and regulatory and market mechanisms to achieve reductions of GHG emissions. CARB is a part of the California Environmental Protection Agency, an organization which reports directly to the Governor's Office in the Executive Branch of California State Government.

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, rates of return on transmission investment, the uniform systems of accounts, rates of depreciation and electric rates involving sales for resale.

The NRC oversees the licensing, construction and operation of nuclear facilities in the United States. 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 reanalyze 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 public places. Most of the franchises have indefinite lives, except for the electric and natural gas franchises with the cities of (with expiration dates as indicated) Encinitas (2012), Chula Vista (2015), San Diego (2020) and Coronado (2028) and the natural gas franchises with the county of San Diego (2029) and the city of Escondido (2035).

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.

NATURAL GAS UTILITY OPERATIONS

The company is engaged in the purchase, sale and distribution of natural gas. The company's resource planning, natural gas 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 classified as either core or noncore customers. Core customers are primarily residential and small commercial and industrial customers, without alternative fuel capability. Noncore customers consist primarily of electric generation, and large commercial and industrial customers.

Most core customers purchase natural gas directly from the company. While customers are permitted to aggregate their natural gas requirement and purchase directly from brokers or producers, the company continues to be obligated to provide reliable supplies of natural gas to serve the requirements of core customers.

Natural Gas Procurement and Transportation

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

SDG&E has natural gas transportation contracts with various interstate pipelines that expire on various dates between 2008 and 2023. SDG&E currently purchases natural gas on a spot basis from Canada, the U.S. Rockies and the southwestern U.S. to fill its long-term pipeline capacity and purchases additional spot-market supplies delivered directly to California for its remaining requirements. All of SDG&E's natural gas is delivered through SoCalGas' pipelines under a long-term transportation agreement. In addition, under separate agreements expiring in March 2008, SoCalGas provides SDG&E up to nine billion cubic feet (Bcf) of storage capacity. A December 2007 CPUC decision directs that, effective April 1, 2008, natural gas procurement for both SDG&E’s and SoCalGas’ natural gas core customers be combined into a single supply portfolio to be administered by SoCalGas. All SDG&E assets associated with its core customer natural gas supply portfolio will be transferred or assigned to SoCalGas.

Demand for Natural Gas

The company faces competition in the residential and commercial customer markets based on the customers' preferences for natural gas compared with other energy products. In the non-core industrial market, some customers are capable of using alternate fuels which can affect the demand for natural gas. The company's ability to maintain its industrial market share is largely dependent on the relative spread between energy prices. 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 U.S. and Canada. In addition, natural gas use is impacted by the performance of other generation sources in the western U.S., including nuclear and coal, renewable energy 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 extended heat waves. Over the long-term, natural gas used to generate electricity will be influenced by additional factors such as the location of new power plant construction and the development of renewable energy resources. Recently, more generation capacity has been constructed outside Southern California than within SDG&E's service area. This new generation will displace the output of older, less-efficient local generation, reducing the use of natural gas for local electric generation. Over the next few years, however, construction and planned construction of smaller natural gas-fired peaking and other electric generation facilities within SDG&E’s service area are expected to result in a slight overall increase in the demand for local natural gas for electric generation.

Effective March 31, 1998, electric industry restructuring provided out-of-state producers the option to provide power to California utility customers. As a result, natural gas demand for electric generation within Southern California competes with electric power generated throughout the western U.S.

Natural gas transported for electric generating plant customers may be significantly affected to the extent that regulatory changes and electric transmission infrastructure investment divert electric generation from the company'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, development of renewable energy resources, development of new natural gas supply sources and general economic conditions can result in significant shifts in demand and market price. The company added 5,000 and 8,000 new customer meters in 2007 and 2006, respectively, representing growth rates of 0.7 percent and 1.0 percent in 2007 and 2006, respectively. The slower growth in 2007 reflects a slowdown in the housing market. The company expects that its growth rate for 2008 will approximate that of 2007.

The natural gas distribution business is seasonal in nature and revenues generally are greater during the winter months. 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.

ELECTRIC UTILITY OPERATIONS

Customers

At December 31, 2007, the company had 1.4 million customer meters consisting of 1,210,600 residential, 146,300 commercial, 500 industrial, 2,000 street and highway lighting and 5,400 direct access. The company's service area covers 4,100 square miles. The company added 10,000 new electric customer meters in 2007 and 17,000 in 2006, representing growth rates of 0.7 percent and 1.3 percent, respectively. The company expects that its growth rate for 2008 will approximate that of 2007.

Resource Planning and Power Procurement

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

Electric Resources

Based on CPUC-approved purchased-power contracts currently in place with its various suppliers, its Palomar and Miramar generating facilities and its 20-percent ownership interest in SONGS, the supply of electric power available to SDG&E as of December 31, 2007, is as follows:

Supplier	Source	Expiration date	MW
PURCHASED-POWER CONTRACTS:			
DWR** -allocated contracts:			
Bear Energy LP	Natural gas	2008 to 2010	700*
Sunrise Power Co. LLC	Natural gas	2012	575
Other (5 contracts)	Natural gas/Wind	2011 to 2013	264
Total			1,539
Other contracts with Qualifying Facilities (QFs):			
Applied Energy Inc.	Cogeneration	2019	107
Yuma Cogeneration	Cogeneration	2024	53
Goal Line Limited Partnership	Cogeneration	2025	50
Other (17 contracts)	Cogeneration	2009 and thereafter	56
Total			266
Other contracts with renewable sources:			
Oasis Power Partners	Wind	2019	60
Kumeyaay	Wind	2025	50
Covanta Delano	Bio-mass	2017	49
PPM Energy	Wind	2018	25
WTE/FPL	Wind	2019	17
Other (8 contracts)	Bio-gas/Hydro	2012 to 2022	31
Total			232
Other long-term and tolling contracts:			
Cabrillo Power I, LLC	Natural Gas	2009	964
LSP South Bay, LLC	Natural Gas	2009	704
Portland General Electric (PGE)	Coal	2013	89
Enernoc	Demand Response/Dist. Generation	2016	25
Total			1,782
Total contracted			3,819
GENERATION:			
Palomar	Natural Gas		550
SONGS	Nuclear		430
Miramar	Natural Gas		45
Total generation			1,025
TOTAL CONTRACTED AND GENERATION			4,844

* Effective January 1, 2008, the quantity will decrease to 325 MW.
** Department of Water Resources

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 most of 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, or are tolls based on available capacity. The prices under these contracts are at the market value at the time the contracts were negotiated.

Natural Gas Supply

SDG&E buys natural gas under short-term contracts for its Palomar and Miramar generating facilities and for the Cabrillo Power I, LLC and LSP South Bay, LLC tolling contracts. Purchases are from various southwestern U.S. suppliers and are primarily based on monthly and spot-market prices. All of SDG&E's natural gas is delivered through SoCalGas' pipelines under a two-year transportation agreement which expires on March 31, 2008.

SDG&E also buys natural gas as the DWR’s limited agent for the DWR-allocated contracts. Most of the natural gas deliveries for the DWR-allocated contracts are transported through the Kern Pipeline under a long-term transportation agreement. The DWR is financially responsible for the costs of gas and transportation.

SONGS

SDG&E has a 20-percent ownership interest in SONGS, which is located south of San Clemente, California. SONGS consists of two operating nuclear generating units and one that is permanently shut down and is being decommissioned. The city of Riverside owns 1.79 percent of Units 2 and 3, and Southern California Edison (Edison), the operator of SONGS, owns the remaining interests.

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.

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 in an independent spent fuel storage installation (ISFSI) licensed by the NRC.

SDG&E has fully recovered its SONGS capital investment through December 31, 2003 and earns a return only on subsequent capital additions, including the company's share of costs associated with planned steam generator replacements.

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

Nuclear Fuel Supply

The nuclear fuel supply cycle includes materials and services (uranium oxide, conversion of uranium oxide to uranium hexafluoride, uranium enrichment services, and fabrication of fuel assemblies) performed by others under various contracts which extend through 2012. The availability and the cost of the various components of the nuclear fuel cycle for SDG&E's 20-percent ownership interest in SONGS in subsequent years cannot be estimated at this time.

Spent fuel from SONGS is being stored on site in both the ISFSI and spent fuel pools. Upon completion of the current phase of Unit 1 decommissioning, the site will have adequate space to build ISFSI storage capacity through 2022, the expiration date of the units' 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 from SONGS. SDG&E pays the DOE a disposal fee of $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 2017 at the earliest.

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 300 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 preapproved by the FERC.

Transmission Arrangements

SDG&E's 500-kV 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 1,163 MW, although it can be less under certain system conditions.

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

SDG&E is in the approval phase for the Sunrise Powerlink, a new 500-kV transmission line between the existing Imperial Valley Substation and a new central substation to be located within the SDG&E system. The proposed rating of the Sunrise Powerlink is 1,000 MW. The project is subject to CPUC approval. Further discussion is provided in Note 10 of the Notes to Consolidated Financial Statements herein.

Transmission Access

The National Energy Policy Act governs procedures for others' requests for transmission service. The FERC approved the California investor-owned utilities' (IOUs) transfer of operation and control of their transmission facilities to the Independent System Operator (ISO) in 1998. Additional information regarding FERC, ISO and transmission issues is provided in Note 10 of the Notes to Consolidated Financial Statements herein.

ENVIRONMENTAL MATTERS

Discussions about environmental issues affecting the company are included in Notes 10 and 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 mechanism, allowing California's IOUs to recover certain hazardous waste cleanup costs, including those related to Superfund sites or similar sites requiring cleanup. Rate 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.

At December 31, 2007, the company had accrued its estimated remaining investigation and remediation liability related to hazardous waste sites, including numerous locations that had been manufactured-gas plants, of $0.4 million, of which 90 percent is authorized to be recovered through the Hazardous Waste Collaborative mechanism. This estimated cost excludes remediation costs of $6 million 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.

Air and Water Quality

The transmission and distribution of natural gas require the operation of compressor stations, which are subject to increasingly stringent air-quality standards, such as those established by the CARB as discussed under "Government Regulation – California Utility Regulation" herein. Costs to comply with these standards are generally recovered in rates.

In connection with the issuance of operating permits, SDG&E and the other owners of SONGS previously reached an 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. SDG&E's share of the cost is estimated to be $36 million, of which $25 million had been incurred at December 31, 2007, and $11 million is accrued for the remaining costs through 2050. In May 2006, the CPUC adopted a decision in Edison's 2006 General Rate Case, in which decision SDG&E is no longer subject to a 50-percent disallowance of cost recovery going forward.

OTHER MATTERS

Employees of Registrant

As of December 31, 2007, the company had 4,774 employees, compared to 4,758 at December 31, 2006.

Labor Relations

Field, technical and some clerical employees at SDG&E are represented by Local 465 International Brotherhood of Electrical Workers. The collective bargaining agreement for these employees covering wages, hours and working conditions is in effect through August 31, 2008. For these same employees, the agreements covering health and welfare benefits and pension benefits are in effect through December 31, 2010 and December 4, 2009, respectively.

ITEM 2. PROPERTIES

Electric Properties

SDG&E owns two natural gas-fired power plants: a 550-MW electric generation facility (the Palomar generation facility) located in Escondido, California, and a 45-MW electric generation facility (the Miramar generation facility) located in San Diego, California. SDG&E's interest in SONGS is described in "Electric Resources" herein.

At December 31, 2007, SDG&E's electric transmission and distribution facilities included substations, and overhead and underground lines. These electric facilities are located in San Diego, Imperial and Orange counties of California and in Arizona, and consist of 1,886 miles of transmission lines and 22,056 miles of distribution lines. Periodically, various areas of the service territory require expansion to accommodate customer growth.

Natural Gas Properties

At December 31, 2007, SDG&E's natural gas facilities, which are located in San Diego and Riverside counties of California, consisted of the Moreno and Rainbow compressor stations, 166 miles of transmission pipelines, 8,335 miles of distribution mains and 6,292 miles of service lines.

Other Properties

SDG&E occupies an office complex in San Diego pursuant to two separate operating leases, both ending in December 2017. One lease has four five-year renewal options and the other lease has three five-year renewal options.

The company owns or leases other land, easements, rights of way, warehouses, offices, operating and maintenance centers, shops, service facilities and equipment necessary in the conduct of its business.

ITEM 3. LEGAL PROCEEDINGS

Except for the matters described in Note 12 of the Notes to Consolidated Financial Statements or referred to in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein, neither the company nor its subsidiary is party to, nor is their property the subject of, any material pending legal proceedings.

On July 13, 2007, SDG&E, one of its employees, and an SDG&E contractor were convicted in a federal jury trial on criminal charges of environmental violations in connection with the 2000 - 2001 dismantlement of a natural gas storage facility. SDG&E was also convicted of a related charge of making a false statement to a government agency. SDG&E is subject to a maximum fine of $2 million. On December 7, 2007, the trial court set aside all of the convictions and granted all of the defendants a new trial on all counts. The government has filed a notice of appeal.

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 dividend declarations is included in the "Statements of Consolidated Comprehensive Income and Changes in Shareholders' Equity" set forth in Item 8 herein.

Dividend Restrictions

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. Additional information regarding these restrictions is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Capital Resources and Liquidity--Dividends" herein.

ITEM 6. SELECTED FINANCIAL DATA

	At December 31, or for the years then ended				
(Dollars in millions)	2007	2006	2005	2004	2003
Income Statement Data:					
Operating revenues	$ 2,852	$ 2,785	$ 2,512	$ 2,274	$ 2,308
Operating income	$ 500	$ 477	$ 393	$ 393	$ 515
Dividends on preferred stock	$ 5	$ 5	$ 5	$ 5	$ 6
Earnings applicable to common shares	$ 283	$ 237	$ 262	$ 208	$ 334
Balance Sheet Data:					
Total assets	$ 8,508	$ 7,795	$ 7,492	$ 6,834	$ 6,461
Long-term debt	$ 1,958	$ 1,638	$ 1,455	$ 1,022	$ 1,087
Short-term debt (a)	$ --	$ 138	$ 66	$ 66	$ 66
Preferred stock subject to mandatory redemption	$ 14	$ 17	$ 19	$ 21	$ 24
Shareholders' equity	$ 2,279	$ 1,994	$ 1,562	$ 1,376	$ 1,343

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

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 2007 Annual Report includes management's discussion and analysis of operating results from 2005 through 2007, and provides information about the capital resources, liquidity and financial performance of San Diego Gas & Electric Company (SDG&E or the company). 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 business, serving 3.4 million consumers, and in the natural gas business, serving 3.1 million consumers. It distributes electric energy, purchased from others or generated from its Palomar and Miramar generating facilities and its 20-percent ownership interest in the San Onofre Nuclear Generating Station (SONGS), through 1.4 million meters in San Diego County and an adjacent portion of southern Orange County, California. It also purchases and distributes natural gas through 840,000 meters in San Diego County and transports electricity and natural gas for others. SDG&E's service territory 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 discussed in Note 3 of the Notes to Consolidated Financial Statements. The company's financial statements include a variable interest entity, Otay Mesa Energy Center LLC (OMEC LLC), as discussed in Note 1 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 Sempra Utilities."

RESULTS OF OPERATIONS

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

(Dollars in millions)	
2007	$ 288
2006	$ 242
2005	$ 267
2004	$ 213
2003	$ 340

The company is subject to regulation by federal, state and local governmental agencies. The primary regulatory agency is the California Public Utility Commission (CPUC), which regulates utility rates and operations in California, except for SDG&E's electric transmission operations, which are regulated by the Federal Energy Regulatory Commission (FERC). The FERC also regulates interstate transportation of natural gas 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.

Electric Revenues and Cost of Electric Fuel and Purchased Power. Electric revenues increased by $47 million (2%) to $2.2 billion, and the cost of electric fuel and purchased power decreased by $22 million (3%) to $699 million in 2007. The increased revenue in 2007 was primarily due to $33 million from higher authorized transmission and electric generation margins, $22 million from the resolution of a regulatory matter, a $24 million increase in authorized base margin on electric distribution and $12 million of higher revenues for recoverable expenses, which are fully offset in other operating expenses. The increases were offset by $20 million from the favorable resolution of a prior year cost recovery issue in 2006 and $22 million lower recovery of electric fuel and purchased power costs in 2007.

Electric revenues increased by $344 million (19%) to $2.1 billion, and the cost of electric fuel and purchased power increased by $97 million (16%) to $721 million in 2006 compared to 2005. The increase in revenue was due to $206 million of increased authorized distribution, generation and transmission base margins, $60 million of higher revenues for recoverable expenses, and the $20 million favorable resolution of a prior year cost recovery issue. The increases were offset by a $28 million demand-side management (DSM) awards settlement in 2005 and $23 million from the 2005 Internal Revenue Service (IRS) decision relating to the sale of SDG&E's former South Bay power plant. In addition, electric revenues and costs increased due to the commencement of commercial operations of the Palomar generating facility in 2006, which contributed $112 million to both 2006 revenues and costs, offset by lower purchased power costs.

Natural Gas Revenues and Cost of Natural Gas. Natural gas revenues increased by $20 million (3%) to $658 million, and the cost of natural gas increased $12 million (3%) to $392 million in 2007. The company's weighted average cost (including transportation charges) per million British thermal units (MMBtu) of natural gas was $7.17 in 2007, $6.94 in 2006 and $8.67 in 2005.

Natural gas revenues decreased by $71 million (10%) to $638 million, and the cost of natural gas decreased by $76 million (17%) to $380 million in 2006 compared to 2005. The decreases in 2006 were due to lower overall average costs of natural gas, which are passed on to customers, offset by higher volumes.

Although the current regulatory framework provides that 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, SDG&E's natural gas procurement Performance-Based Regulation (PBR) mechanism allows the company to share in the savings or costs from buying natural gas for its customers below or above market-based monthly benchmarks. The mechanism permits full recovery of all costs within a tolerance band around the benchmark price. The costs or savings outside the tolerance band are shared between customers and shareholders. Further discussion is provided in Notes 1 and 11 of the Notes to Consolidated Financial Statements.

The tables below summarize the electric and natural gas volumes and revenues by customer class for the years ended December 31, 2007, 2006 and 2005.

Electric Distribution and Transmission
(Volumes in millions of kilowatt-hours, dollars in millions)

	2007		2006		2005	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
Residential	7,520	$ 980	7,501	$ 910	7,075	$ 738
Commercial	7,154	852	6,983	723	6,674	654
Industrial	2,275	229	2,261	181	2,159	142
Direct access	3,220	118	3,390	133	3,213	114
Street and highway lighting	107	12	102	10	93	11
	20,276	2,191	20,237	1,957	19,214	1,659
Balancing accounts and other		3		190		144
Total		$ 2,194		$ 2,147		$ 1,803

Although commodity costs associated with long-term contracts allocated to SDG&E from the California Department of Water Resources (and the revenues to recover those costs) are not included in the Statements of Consolidated Income, as discussed in Note 1 of the Notes to Consolidated Financial Statements, the associated volumes and distribution revenues are included in the above table.

Natural Gas Sales, Transportation and Exchange
(Volumes in billion cubic feet, dollars in millions)

	Natural Gas Sales		Transportation and Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
2007:						
Residential	32	$ 405	--	$ --	32	$ 405
Commercial and industrial	16	160	5	7	21	167
Electric generation plants	--	1	60	40	60	41
	48	$ 566	65	$ 47	113	613
Balancing accounts and other						45
Total						$ 658
2006:						
Residential	31	$ 397	--	$ --	31	$ 397
Commercial and industrial	17	169	5	7	22	176
Electric generation plants	--	2	65	44	65	46
	48	$ 568	70	$ 51	118	619
Balancing accounts and other						19
Total						$ 638
2005:						
Residential	31	$ 381	--	$ --	31	$ 381
Commercial and industrial	17	174	4	5	21	179
Electric generation plants	1	3	59	39	60	42
	49	$ 558	63	$ 44	112	602
Balancing accounts and other						107
Total						$ 709

Other Operating Expenses. Other operating expenses were $797 million, $774 million and $603 million in 2007, 2006 and 2005, respectively. The increase in 2007 was due to $5 million higher recoverable expenses (offset in revenues) and $23 million higher other operational costs, offset by $5 million lower SONGS operating costs. The increase in 2006 compared to 2005 was due to $72 million higher recoverable expenses, $33 million related to the 2005 recovery of line losses and grid management charges arising from a favorable settlement with the Independent System Operator (ISO), an independent operator of California's wholesale transmission grid, $24 million higher SONGS operating costs and a $42 million increase in various other operational costs.

Litigation Expense. Litigation expense was $10 million, $3 million and $52 million for 2007, 2006 and 2005, respectively. The higher amount in 2005 was primarily due to an increase in litigation reserves related to a settlement of matters arising from the 2000 - 2001 California energy crisis. Note 12 of the Notes to Consolidated Financial Statements provides additional information concerning this matter.

Interest Income. Interest income was $8 million, $6 million and $23 million in 2007, 2006 and 2005, respectively. The decrease in 2006 compared to 2005 was primarily due to $12 million lower interest as a result of income tax audit settlements in 2005.

Interest Expense. Interest expense was $96 million, $97 million and $74 million in 2007, 2006 and 2005, respectively. The increase in 2006 compared to 2005 was primarily due to increased borrowings to finance the purchase of the Palomar generating facility and interest expense related to the accretion of the California energy crisis litigation settlement liability.

Income Taxes. Income tax expense was $135 million, $152 million and $89 million in 2007, 2006 and 2005, respectively. The corresponding effective income tax rates were 32 percent, 39 percent and 25 percent. The decrease in income tax expense in 2007 was primarily due to a lower effective tax rate resulting from higher favorable resolution of prior years' income tax issues. The decrease was partially offset by the effect of higher pretax income in 2007. The increase in 2006 expense compared to 2005 was due to the higher effective tax rate and higher pretax income. The increase in the effective tax rate in 2006 was due primarily to a $60 million favorable resolution of prior years' income tax issues in 2005, compared to $2 million unfavorable in 2006.

Net Income. SDG&E recorded net income of $288 million, $242 million and $267 million in 2007, 2006 and 2005, respectively. The increase in 2007 was primarily due to $18 million from the higher favorable resolution of prior years' income tax issues in 2007, $15 million from higher electric transmission earnings and $7 million due to the Palomar electric generation facility operating for twelve months in 2007 as compared to nine months in 2006. Net income in 2007 also included $26 million from the resolution of a regulatory item associated with the disposition of a power plant in a prior year. Regulatory items in 2006 included a $13 million resolution of a prior-year cost recovery issue, $8 million due to the CPUC authorization for retroactive recovery on SONGS revenues related to a computational error in the 2004 Cost of Service, and $4 million due to FERC approval to recover prior-year ISO charges in 2006.

The decrease in 2006 compared to 2005 was primarily due to $60 million associated with the favorable resolution of prior years' income tax issues in 2005, the $23 million recovery of costs in 2005 associated with an IRS decision relating to the sale of the South Bay power plant and $22 million related to a DSM awards settlement in 2005. These items were offset by a $42 million increase in earnings from electric generation activities including the commencement of commercial operation of the Palomar generating facility in 2006, $28 million due to the litigation expense in 2005 related to the California energy crisis matter and a $13 million increase in earnings due to lower income tax expense primarily resulting from a lower effective tax rate in 2006 (excluding the effect of the resolution of prior years' income tax issues in 2005). Resolution of regulatory items was $25 million in 2006 as compared to $23 million in 2005. The 2005 regulatory item of $23 million resulted from FERC approval to recover prior-year ISO charges (as discussed further in Note 12 of the Notes to Consolidated Financial Statements).

CAPITAL RESOURCES AND LIQUIDITY

The company's utility operations generally are the major source of liquidity. In addition, cash 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, 2007, the company had $158 million in unrestricted cash and cash equivalents and $500 million in available unused credit on its committed line, which is shared with SoCalGas and is discussed more fully in Note 3 of the Notes to Consolidated Financial Statements. Management believes that these amounts and cash flows from operations and 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, investing and financing activities in a manner consistent with its intention to maintain strong, investment-quality credit ratings.

In connection with the purchase of the Palomar generating facility in 2006, the company received a $200 million capital contribution from Sempra Energy. As a result of the company's projected capital expenditure program, SDG&E has elected to suspend the payment of dividends on its common stock to Sempra Energy, and the level of future common dividends may be affected during periods of increased capital expenditures.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $660 million, $397 million and $338 million for 2007, 2006 and 2005, respectively. Cash provided by operating activities in 2007 increased by $263 million (66%). The change was primarily due to a $150 million increase in income from continuing operations (adjusted for noncash items) and a $133 million increase in overcollected regulatory balancing accounts in 2007 compared to a decrease of $14 million in 2006.

The increase in cash provided by operating activities in 2006 compared to 2005 was primarily due to a $138 million decrease in the reduction of overcollected regulatory balancing accounts in 2006 as compared to 2005 and a $95 million decrease in accounts receivable, partially offset by a $53 million decrease in other liabilities, a $50 million decrease in current liabilities, a $37 million increase in interest receivable and a $29 million increase in inventories.

The company made pension plan and other postretirement benefit plan contributions of $27 million and $15 million, respectively, during 2007, $30 million and $12 million, respectively, during 2006 and $21 million and $7 million, respectively, during 2005.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $707 million, $1.1 billion and $458 million for 2007, 2006 and 2005, respectively. Cash used in investing activities in 2007 decreased by $360 million (34%) primarily due to the purchase of the Palomar generating facility and higher expenditures for the Otay Metro Powerloop transmission project in 2006, partially offset by increased capital spending resulting from the October 2007 Southern California wildfires.

The increase in cash used in investing activities in 2006 compared to 2005 was primarily due to a $606 million increase in capital expenditures in 2006, including the purchase of the Palomar generating facility and higher expenditures for the Otay Metro Powerloop project.

Future Capital Expenditures for Utility Plant

Significant capital expenditures and investments in 2008 are expected to include $700 million for additions to the company's natural gas and electric distribution, electric transmission and generation systems, and advanced metering infrastructure. These expenditures are expected to be financed by cash flows from operations and security issuances. These amounts exclude capital expenditures of OMEC LLC.

Over the next five years, the company expects to make capital expenditures of $5 billion at a rate ranging from $600 million to $1.3 billion per year.

The company has an application on file with the CPUC for the Sunrise Powerlink, a proposed new transmission power line between the San Diego region and the Imperial Valley of Southern California. The proposed line would be able to deliver 1,000 MW and is estimated to cost $1.2 billion. Additional information on the Sunrise Powerlink is provided in Note 10 of the Notes to Consolidated Financial Statements.

Capital expenditure amounts include the portion of AFUDC (allowance for funds used during construction) related to debt, and exclude the portion of AFUDC related to equity. AFUDC is discussed in Note 1 of the Notes to Consolidated Financial Statements.

Construction programs are periodically reviewed and revised by the company in response to changes in regulation, economic conditions, competition, customer growth, inflation, customer rates, the cost of capital and environmental requirements, as discussed in Notes 10 and 12 of the Notes to Consolidated Financial Statements.

The company intends to finance its capital expenditures in a manner that will maintain its strong investment-grade ratings and capital structure.

The amounts and timing of capital expenditures are subject to approvals by the CPUC, the FERC and other regulatory bodies.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash provided by financing activities totaled $167 million, $443 million and $347 million for 2007, 2006 and 2005, respectively. Cash provided by financing activities in 2007 decreased by $276 million (62%), primarily due to the $200 million capital contribution made by Sempra Energy in 2006 and a $98 million decrease in issuances of long-term debt in 2007.

The increase in cash provided by financing activities in 2006 compared to 2005 was primarily due to the $200 million capital contribution from Sempra Energy and a $72 million increase in short-term debt, offset by a $161 million increase in payments on long-term debt and an $89 million decrease in issuances of long-term debt. In addition, the company did not pay any common dividends in 2006 as compared to $75 million of common dividends paid in 2005.

Long-Term Debt

In September 2007, the company publicly offered and sold $250 million of 6.125-percent first mortgage bonds, maturing in 2037. The company’s variable interest entity, OMEC LLC, had construction loan borrowings of $63 million.

In September 2006, the company issued $161 million of variable-rate first mortgage bonds, maturing in 2018, and applied the proceeds in November 2006 to retire an identical amount of first mortgage bonds and related tax-exempt industrial development bonds of a similar weighted-average maturity. The bonds will 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 have been loaned to the company and will be repaid with payments on the first mortgage bonds.

In June 2006, the company publicly offered and sold $250 million of 6-percent first mortgage bonds, maturing in 2026.

In November 2005, the company publicly offered and sold $250 million of 5.30-percent first mortgage bonds, maturing in 2015. In May 2005, the company publicly offered and sold $250 million of 5.35-percent first mortgage bonds, maturing in 2035.

Payments on long-term debt in 2007 were $66 million, the remaining outstanding balance of rate-reduction bonds.

Payments on long-term debt in 2006 included $161 million of the company's first mortgage bonds and $66 million of rate-reduction bonds.

Payments on long-term debt in 2005 were $66 million related to the company's rate-reduction bonds.

Note 3 of the Notes to Consolidated Financial Statements provides information concerning lines of credit and further discussion of debt activity.

Dividends

The company did not pay any common dividends to Sempra Energy in 2007 and 2006 to preserve cash to fund the company’s capital expenditures program, but did pay $75 million of common dividends to Sempra Energy in 2005.

The payment and amount of future dividends are at 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, 2007, the company could have provided a total (combined loans and dividends) of $29 million to Sempra Energy.

Capitalization

At December 31, 2007, total capitalization, including all debt, was $4.4 billion. The debt-to-capitalization ratio was 45 percent at December 31, 2007. Significant changes affecting capitalization during 2007 included an increase in long-term debt, reductions in short-term borrowings, an increase in minority interest, and comprehensive income. Additional discussion related to the significant changes is provided in Note 3 of the Notes to Consolidated Financial Statements and "Results of Operations" above.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2007. Additional information concerning commitments is provided above and in Notes 2, 3, 6, 9 and 12 of the Notes to Consolidated Financial Statements.

(Dollars in millions)	2008	2009 and 2010	2011 and 2012	Thereafter	Total
Long-term debt	$ --	$ --	$ --	$ 1,958	$ 1,958
Interest on debt (1)	90	190	197	1,376	1,853
Operating leases	22	42	36	63	163
Litigation reserves	12	12	12	11	47
Purchased-power contracts	360	764	680	2,536	4,340
Natural gas contracts (2)	26	29	26	109	190
Preferred stock subject to mandatory redemption	14	--	--	--	14
Construction commitments	7	8	1	--	16
SONGS decommissioning	10	1	--	400	411
Other asset retirement obligations	4	7	7	139	157
Pension and postretirement benefit obligations (3)	57	115	122	280	574
Environmental commitments	8	2	3	4	17
Totals	$ 610	$ 1,170	$ 1,084	$ 6,876	$ 9,740

(1) Expected interest payments were calculated using the stated interest rate for fixed rate obligations, including floating-to-fixed interest rate swaps. Expected interest payments were calculated based on forward rates in effect at December 31, 2007 for variable rate obligations.

(2) Upon the combination of the company's and SoCalGas' core natural gas portfolios, as discussed in Note 11 of the Notes to Consolidated Financial Statements, these commitments will be assigned or transferred to SoCalGas.

(3) Amounts are after reduction for the Medicare Part D subsidy and only include expected payments to the plans for the next 10 years.

The table excludes intercompany debt and individual contracts that have annual cash requirements less than $1 million. The table also excludes income tax liabilities of $26 million recorded in accordance with Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109* (FIN 48), because the company is unable to reasonably estimate the timing of future payments of these liabilities due to uncertainties in the timing of the effective settlement of tax positions. Additional information on FIN 48 is provided in Note 2 of the Notes to Consolidated Financial Statements.

Credit Ratings

Credit ratings remained at investment grade levels in 2007. As of January 31, 2008, company credit ratings 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, 2008, the company has a stable ratings outlook 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. Performance will also depend on the CPUC’s final decision regarding the 2008 General Rate Case and the successful completion of capital projects which are discussed in various places in this report. These factors are discussed in Notes 10 and 11 of the Notes to Consolidated Financial Statements.

Litigation

Note 12 of the Notes to Consolidated Financial Statements describes litigation, the ultimate resolution of which could have a material adverse effect on future performance.

Industry Developments

Notes 10 and 11 of the Notes to Consolidated Financial Statements describe electric and natural gas regulation and rates, and other pending proceedings and investigations.

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.

The company has policies governing its market risk management and trading activities. The company maintains a risk management committee, organization and processes to provide oversight of these activities. The committee, consisting of senior officers, establishes policy for and oversees energy risk management activities and monitors the results of trading and other activities to ensure compliance with the company's stated energy risk management and trading policies. This includes monitoring daily, detailed information detailing positions regarding market positions that create credit, liquidity and market risk. Independently from the company’s energy procurement department, the oversight organization and committee monitor energy price risk management and measure and report the credit, liquidity and market risk associated with these positions.

Along with other tools, the company uses Value at Risk (VaR) to measure daily 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 risk management oversight organization. Historical and implied volatilities and correlations between instruments and positions are used in the calculation.

The company uses energy and natural gas derivatives to manage natural gas and energy price risk associated with servicing load requirements. The use of energy and natural gas derivatives is subject to certain limitations imposed by company policy and is in compliance with risk management and trading activity plans that have been filed and approved by the CPUC. Any costs or gains/losses associated with the use of energy and natural gas derivatives, which use is in compliance with CPUC approved plans, are considered to be commodity costs that are passed on to customers on a substantially concurrent basis.

Revenue recognition is discussed in Note 1 of the Notes to Consolidated Financial Statements 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, 2007 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 the costs of electric procurement and natural gas purchases, and 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 are 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 its market risk management framework. As of December 31, 2007, the company's VaR was not material, and the procurement activities were in compliance with the procurement plans filed with and approved by the CPUC.

Interest Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its short-term and long-term debt. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures. The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall costs of borrowing.

At December 31, 2007, after the effects of interest-rate swaps, the company had $1.8 billion of fixed-rate, long-term debt and $168 million of variable-rate, long-term 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, 2007, the company's fixed-rate, long-term debt, after the effects of interest-rate swaps, had a one-year VaR of $320 million and variable-rate, long-term debt, after the effects of interest-rate swaps, had a one-year VaR of $17 million.

At December 31, 2007, the total notional amount of interest-rate swap transactions ranges from $324 million to $628 million (ranges relate to amortizing notional amounts). Note 8 of the Notes to Consolidated Financial Statements provides further information regarding interest-rate swap transactions.

In addition, the company is subject to the effect of interest-rate fluctuations on the assets of its pension plans, other postretirement benefit plans and the nuclear decommissioning trusts. However, the effects of these fluctuations are expected to be passed on to customers.

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 policies governing the management of credit risk that are administered by the company's credit department and overseen by its risk management committee. Using rigorous models, this oversight includes calculating current and potential credit risk on a daily basis and monitoring actual balances in comparison to approved limits. The company avoids concentration of counterparties whenever possible, and management believes its credit policies 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 believes that adequate reserves have been provided for counterparty nonperformance.

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.

As noted above under "Interest Rate Risk," 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND KEY NONCASH 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 in the United States of America and the regulations of the Securities and Exchange Commission, are the following:

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Contingencies		
Statement of Financial Accounting Standards (SFAS) 5, *Accounting for Contingencies*, establishes the amounts and timing of when the company provides for contingent losses. The company continuously assesses potential loss contingencies for litigation claims, environmental remediation and other events.	The company accrues losses for the estimated impacts of various conditions, situations or circumstances involving uncertain outcomes. For loss contingencies, the loss is accrued if (1) information is available that indicates it is probable that the loss has been incurred, given the likelihood of uncertain future events, and (2) the amounts of the loss can be reasonably estimated. SFAS 5 does not permit the accrual of contingencies that might result in gains.	Details of the company's issues in this area are discussed in Note 12 of the Notes to Consolidated Financial Statements.
Regulatory Accounting		
SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, has a significant effect on the way the Sempra Utilities record assets and liabilities, and the related revenues and expenses that would not be recorded absent the principles contained in SFAS 71.	The company records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. Similarly, the company records regulatory liabilities for amounts recovered in rates in advance of the expenditure. The company reviews probabilities associated with regulatory balances whenever new events occur, such as changes in the regulatory environment or the utility's competitive position, issuance of a regulatory commission order or passage of new legislation. To the extent that circumstances associated with regulatory balances change, the regulatory balances could be adjusted.	Details of the company's regulatory assets and liabilities are discussed in Note 1 of the Notes to Consolidated Financial Statements.

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Income Taxes		
SFAS 109, *Accounting for Income Taxes*, governs the way the company provides for income taxes.	The company's income tax expense and related balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve judgments and estimates of the timing and probability of recognition of income and deductions by taxing authorities. The anticipated resolution of income-tax issues considers past resolutions 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. The likelihood of deferred tax recovery is based on analyses of the deferred tax assets and the company's expectation of future taxable income, based on its strategic planning.	Actual income taxes could vary from estimated amounts due to the future impacts of various items including changes in tax laws, the company's financial condition in future periods, and the resolution of various income tax issues between the company and the various taxing authorities. Details of the company's issues in this area are discussed in Note 5 of the Notes to Consolidated Financial Statements.
FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements. FIN 48 addresses how an entity should recognize, measure, classify and disclose in its financial statements uncertain tax positions that it has taken or expects to take in an income tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.	For a position to qualify for benefit recognition under FIN 48, the position must have at least a "more likely than not" chance of being sustained (based on the position’s technical merits) upon challenge by the respective authorities. The term "more likely than not" means a likelihood of more than 50 percent. If the company does not have a more likely than not position with respect to a tax position, then the company may not recognize any of the potential tax benefit associated with the position. A tax position that meets the "more likely than not" recognition shall initially and subsequently be measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon the effective resolution of the tax position.	Unrecognized tax benefits involve management judgment regarding the likelihood of the benefit being sustained. The final resolution of uncertain tax positions could result in adjustments to recorded amounts and may affect the company’s results of operations, financial position and cash flows. Additional information related to accounting for uncertainty in income taxes is discussed in Note 2 of the Notes to Consolidated Financial Statements.

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Fair Value Measurements SFAS 157, *Fair Value Measurements*, was adopted by the company in the first quarter of 2007. SFAS 157 defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. SFAS 157 does not expand the use of fair value accounting in any new circumstances. SFAS 157: (1) establishes that fair value is based on a hierarchy of inputs into the valuation process (as described in Note 8 of the Notes to Consolidated Financial Statements), (2) clarifies that an issuer's credit standing should be considered when measuring liabilities at fair value, (3) precludes the use of a liquidity or blockage factor discount when measuring instruments traded in an actively quoted market at fair value, and (4) requires costs related to acquiring instruments carried at fair value to be recognized as expense when incurred. The following assets and liabilities are recorded at fair value on a recurring basis as of December 31, 2007: (1) derivatives and (2) the assets of the company’s nuclear decommissioning trusts.	As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under SFAS 157, the company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities carried at fair value. The company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The company primarily applies the market approach for recurring fair value measurements and endeavors to utilize the best available information. Accordingly, the company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The company is able to classify fair value balances based on the observability of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS 157 are as follows: Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.	The company's assessment of the significance of a particular input to the fair value measurements requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. Generally, the company’s results of operations are not significantly impacted by the assets and liabilities accounted for at fair value because of the principles contained in SFAS 71. There was no transition adjustment as a result of the company's adoption of SFAS 157. Additional information relating to fair value measurement is discussed in Notes 2 and 8 of the Notes to Consolidated Financial Statements.

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Fair Value Measurements (continued)		
	Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options. Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value from the perspective of a market participant. At each balance sheet date, the company performs an analysis of all instruments subject to SFAS 157 and includes in level 3 all of those whose fair value is based on significant unobservable inputs.	

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Derivatives		
SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, and related Emerging Issues Task Force Issues govern the accounting requirements for derivatives.	The company values derivative instruments at fair value on the balance sheet. Depending on the purpose for the contract and the applicability of hedge accounting, the impact of instruments may be offset in earnings, on the balance sheet, or in other comprehensive income. The company also utilizes normal purchase or sale accounting for certain contracts.	The application of hedge accounting to certain derivatives and the normal purchase or sale election is made on a contract-by-contract basis. Utilizing hedge accounting or the normal purchase or sale election in a different manner could materially impact reported results of operations. The effects of derivatives' accounting have a significant impact on the balance sheet of the company but have no significant effect on its results of operations because of the principles contained in SFAS 71 and the application of the normal purchase or sale election. Details of the company's financial instruments are discussed in Note 8 of the Notes to Consolidated Financial Statements.

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Defined Benefit Plans		
The company has funded and unfunded noncontributory defined benefit plans that together cover substantially all of its employees. The company also has other postretirement benefit plans covering substantially all of its employees. The company accounts for its pension and other postretirement benefit plans under SFAS 87, *Employers' Accounting for Pensions*, and SFAS 106, *Employers' Accounting for Postretirement Benefits Other than Pensions*, respectively, and under SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).*	The measurement of the company's pension and postretirement obligations, costs and liabilities is dependent on a variety of assumptions used by the company. The critical assumptions used in developing the required estimates include the following key factors: discount rate, expected return on plan assets, health-care cost trend rates, mortality rates, rate of compensation increases and payout elections (lump sum or annuity). These assumptions are reviewed on an annual basis prior to the beginning of each year and updated when appropriate. The company considers current market conditions, including interest rates, in making these assumptions.	The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter participant life spans, or more or fewer lump sum versus annuity payout elections made by plan participants. The health-care cost trend rate is 9.48 percent for 2007. Increasing the health-care cost trend rate by one percentage point would increase the accumulated obligation for postretirement benefit plans by $5 million and total service and interest cost by $1 million. Decreasing the health-care cost trend rate by one percentage point would decrease the accumulated obligation by $5 million and total service and interest cost by $1 million. However, these differences have minimal impact on the company's net income due to rate recovery of most benefit plan costs. Additional discussion of pension plan assumptions is included in Note 6 of the Notes to Consolidated Financial Statements.

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 Sempra Energy board of directors.

Key noncash performance indicators for the company include number of customers and natural gas volumes and electricity sold. The information is provided in "Results of Operations."

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had or may have a significant effect on the company's financial statements are described in Note 2 of the Notes to Consolidated Financial Statements.

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

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management is responsible for the preparation of the company's consolidated financial statements and related information appearing in this report. Management believes that the consolidated financial statements fairly present the form and substance of transactions and that the financial statements reasonably present the company's financial position and results of operations in conformity with accounting principles generally accepted in the United States of America. Management also has included in the company's financial statements amounts that are based on estimates and judgments, which it believes are reasonable under the circumstances.

The board of directors of Sempra Energy, the company's parent company, has an Audit Committee composed of six non-management directors. The committee meets periodically with financial management and the internal auditors to review accounting, control, auditing and financial reporting matters.

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 Rules 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, 2007. The effectiveness of the company’s internal control over financial reporting as of December 31, 2007, has been audited by Deloitte & Touche LLP, as stated in their report, which is included in Item 8.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of San Diego Gas & Electric Company and subsidiary (the "Company") as of December 31, 2007 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, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007 of the Company and our report dated February 25, 2008 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of two new accounting standards in 2007.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 25, 2008

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, 2007 and 2006, and the related statements of consolidated income, comprehensive income and changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. 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 San Diego Gas & Electric Company and subsidiary as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board ("FASB") Statement No. 157, *Fair Value Measurements,* effective January 1, 2007 and FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109,* effective January 1, 2007. As discussed in Note 6 to the consolidated financial statements, the Company adopted FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* effective December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, 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 25, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 25, 2008

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED INCOME

(Dollars in millions)	Years ended December 31, 2007	2006	2005
Operating revenues			
Electric	$ 2,194	$ 2,147	$ 1,803
Natural gas	658	638	709
Total operating revenues	2,852	2,785	2,512
Operating expenses			
Cost of electric fuel and purchased power	699	721	624
Cost of natural gas	392	380	456
Other operating expenses	797	774	603
Depreciation and amortization	301	291	264
Franchise fees and other taxes	155	140	119
Litigation expense	10	3	52
Gains on sale of assets	(2)	(1)	(1)
Impairment losses	--	--	2
Total operating expenses	2,352	2,308	2,119
Operating income	500	477	393
Other income, net	11	8	14
Interest income	8	6	23
Interest expense	(96)	(97)	(74)
Income before income taxes	423	394	356
Income tax expense	135	152	89
Net income	288	242	267
Preferred dividend requirements	5	5	5
Earnings applicable to common shares	$ 283	$ 237	$ 262

See Notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 158	$ 9
Accounts receivable – trade	207	206
Accounts receivable – other	49	26
Interest receivable	1	15
Due from unconsolidated affiliates	22	24
Income taxes receivable	56	25
Deferred income taxes	67	41
Inventories	113	97
Regulatory assets arising from fixed-price contracts and other derivatives	52	83
Other regulatory assets	14	69
Other	60	71
Total current assets	799	666
Other assets:		
Due from unconsolidated affiliate	5	5
Deferred taxes recoverable in rates	312	318
Regulatory assets arising from fixed-price contracts and other derivatives	309	353
Regulatory assets arising from pensions and other postretirement benefit obligations	162	220
Other regulatory assets	48	59
Nuclear decommissioning trusts	739	702
Sundry	123	72
Total other assets	1,698	1,729
Property, plant and equipment:		
Property, plant and equipment	8,282	7,495
Less accumulated depreciation and amortization	(2,271)	(2,095)
Property, plant and equipment, net	6,011	5,400
Total assets	$ 8,508	$ 7,795

See Notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2007	December 31, 2006
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	$ --	$ 72
Accounts payable	290	273
Due to unconsolidated affiliates	10	5
Regulatory balancing accounts, net	298	165
Fixed-price contracts and other derivatives	61	83
Customer deposits	52	47
Mandatorily redeemable preferred securities	14	3
Current portion of long-term debt	--	66
Other	259	287
Total current liabilities	984	1,001
Long-term debt	1,958	1,638
Deferred credits and other liabilities:		
Customer advances for construction	33	38
Pension and other postretirement benefit obligations, net of plan assets	190	249
Deferred income taxes	506	520
Deferred investment tax credits	29	31
Regulatory liabilities arising from removal obligations	1,335	1,311
Asset retirement obligations	554	462
Fixed-price contracts and other derivatives	329	353
Mandatorily redeemable preferred securities	--	14
Deferred credits and other	176	184
Total deferred credits and other liabilities	3,152	3,162
Minority interest	135	--
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock not subject to mandatory redemption	79	79
Common stock (255 million shares authorized; 117 million shares outstanding; no par value)	1,138	1,138
Retained earnings	1,078	796
Accumulated other comprehensive income (loss)	(16)	(19)
Total shareholders' equity	2,279	1,994
Total liabilities and shareholders' equity	$ 8,508	$ 7,795

See Notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years ended December 31, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 288	$ 242	$ 267
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	301	291	264
Deferred income taxes and investment tax credits	(40)	(130)	37
Noncash rate-reduction bond expense	55	60	68
Other	12	3	(3)
Changes in other assets	5	9	13
Changes in other liabilities	(5)	(16)	37
Changes in working capital components:			
Accounts receivable	(43)	39	(56)
Interest receivable	(1)	2	39
Due to/from affiliates, net	7	(12)	(1)
Inventories	(16)	(19)	10
Other current assets	6	(19)	(16)
Income taxes	(31)	(32)	(231)
Accounts payable	10	9	28
Regulatory balancing accounts	133	(14)	(152)
Other current liabilities	(21)	(16)	34
Net cash provided by operating activities	660	397	338
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	(714)	(1,070)	(464)
Purchases of nuclear decommissioning trust assets	(587)	(481)	(230)
Proceeds from sales by nuclear decommissioning trusts	592	484	234
Decrease (increase) in loans to affiliates, net	--	(1)	1
Proceeds from sale of assets	2	1	1
Net cash used in investing activities	(707)	(1,067)	(458)
CASH FLOWS FROM FINANCING ACTIVITIES			
Capital contribution	--	200	--
Common dividends paid	--	--	(75)
Preferred dividends paid	(5)	(5)	(5)
Redemptions of preferred stock	(3)	(3)	(3)
Issuances of long-term debt	313	411	500
Payments on long-term debt	(66)	(227)	(66)
Decrease (increase) in short-term debt, net	(72)	72	--
Other	--	(5)	(4)
Net cash provided by financing activities	167	443	347
Increase (decrease) in cash and cash equivalents	120	(227)	227
Cash and cash equivalents, January 1	9	236	9
Cash assumed in connection with FIN 46(R) initial consolidation	29	--	--
Cash and cash equivalents, December 31	$ 158	$ 9	$ 236

See Notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years ended December 31, 2007	2006	2005
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	$ 85	$ 91	$ 66
Income tax payments, net of refunds	$ 206	$ 313	$ 291
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING ACTIVITY			
Increase in accounts payable from investments in property, plant and equipment	$ 37	$ 21	$ 15

See Notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME AND CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2007, 2006 and 2005

(Dollars in millions)	Comprehensive Income	Preferred Stock Not Subject to Mandatory Redemption	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2004		$ 79	$ 938	$ 372	$ (13)	$ 1,376
Net income	$ 267			267		267
Pension adjustment	(1)				(1)	(1)
Comprehensive income	$ 266					
Preferred stock dividends declared				(5)		(5)
Common stock dividends declared				(75)		(75)
Balance at December 31, 2005		79	938	559	(14)	1,562
Net income	$ 242			242		242
Pension adjustment	(2)				(2)	(2)
Comprehensive income	$ 240					
Adoption of FASB Statement No. 158					(3)	(3)
Preferred stock dividends declared				(5)		(5)
Capital contribution			200			200
Balance at December 31, 2006		79	1,138	796	(19)	1,994
Adoption of FIN 48				(1)		(1)
Net income	$ 288			288		288
Financial instruments	(1)				(1)	(1)
Pension adjustment	4				4	4
Comprehensive income	$ 291					
Preferred stock dividends declared				(5)		(5)
Balance at December 31, 2007		$ 79	$ 1,138	$ 1,078	$ (16)	$ 2,279

See Notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

Principles of Consolidation

The Consolidated Financial Statements include the accounts of San Diego Gas & Electric Company (SDG&E or the company), its sole subsidiary, SDG&E Funding LLC, and Otay Mesa Energy Center LLC (OMEC LLC), a variable interest entity of which SDG&E is the primary beneficiary, as discussed below. 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. All material intercompany accounts and transactions have been eliminated.

Sempra Energy also indirectly owns all of the common stock of Southern California Gas Company (SoCalGas). SDG&E and SoCalGas are collectively referred to herein as the Sempra Utilities.

As a subsidiary, the company receives certain services from Sempra Energy, for which it is charged its allocable share of the cost of such services. Management believes that the cost is reasonable and 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 accounting principles generally accepted in the United States of America (GAAP) 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. Although management believes the estimates and assumptions are reasonable, actual amounts ultimately may differ significantly from those estimates.

Regulatory Matters

Effects of Regulation

The accounting policies of the company conform with GAAP for regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

The company prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) 71*, Accounting for the Effects of Certain Types of Regulation* (SFAS 71), 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. 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, 2007, represent net payables (payables net of receivables) that are returned to customers through the reduction of future rates.

Except for certain costs subject to balancing account treatment, fluctuations in most operating and maintenance accounts from forecasted amounts approved by the CPUC in establishing rates affect utility earnings. Balancing accounts provide a mechanism for charging utility customers, over time, 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 volumes and costs, 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)	2007	2006
Fixed-price contracts and other derivatives	$ 361	$ 429
Recapture of temporary rate reduction*	--	56
Deferred taxes recoverable in rates	312	318
Unamortized loss on reacquired debt, net	34	38
Pension and other postretirement benefit obligations	162	220
Removal obligations**	(1,335)	(1,311)
Environmental costs	11	16
Other	17	18
Total	$ (438)	$ (216)

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

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

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

(Dollars in millions)	2007	2006
Current regulatory assets	$ 66	$ 152
Noncurrent regulatory assets	831	950
Current regulatory liabilities*	--	(7)
Noncurrent regulatory liabilities	(1,335)	(1,311)
Total	$ (438)	$ (216)

* Included in Other Current Liabilities.

Regulatory assets arising from fixed-price contracts and other derivatives are offset by corresponding liabilities arising from purchased power and natural gas transportation contracts. The regulatory asset is reduced as payments are made for services under these contracts. Deferred taxes recoverable in rates are based on current regulatory ratemaking and income tax laws. SDG&E expects to recover net regulatory assets related to deferred income taxes over the lives of the assets that give rise to the accumulated deferred income taxes. The regulatory asset related to the recapture of a temporary rate reduction was amortized simultaneously with the amortization of the related rate-reduction bond liability and was fully recovered by the end of 2007. The regulatory assets related to unamortized losses on reacquired debt are being recovered over the remaining original amortization periods of the loss on reacquired debt over periods ranging from four months to 20 years. Regulatory assets related to environmental costs represent the portion of the company's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount is expected to be recovered in future rates as expenditures are made. Regulatory assets related to pension and other postretirement benefit obligations are offset by corresponding liabilities and are being recovered in rates as the costs are incurred.

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 $2 million at December 31, 2007, 2006 and 2005, respectively. The company recorded provisions for doubtful accounts of $4 million, $2 million and $3 million in 2007, 2006 and 2005, respectively. The company wrote off doubtful accounts of $4 million, $2 million and $3 million in 2007, 2006 and 2005, respectively.

Inventories

At December 31, 2007, inventory shown on the Consolidated Balance Sheets included natural gas of $49 million, and materials and supplies of $64 million. The corresponding balances at December 31, 2006 were $43 million and $54 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 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* (SFAS 109), 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 require regulated enterprises to recognize regulatory assets or liabilities to offset deferred tax liabilities and assets, respectively, if it is probable that such amounts will be recovered from, or returned to, customers.

Note 2 describes the impact of the adoption of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109.*

Property, Plant and Equipment

Property, plant and equipment 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 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), as discussed below. The cost of most retired depreciable utility plant minus salvage value is charged to accumulated depreciation.

Property, plant and equipment balances by major functional categories are as follows:

	Property, Plant and Equipment at December 31,		Depreciation rates for the years ended December 31,		
(Dollars in billions)	2007	2006	2007	2006	2005
Natural gas operations	$ 1.1	$ 1.1	3.43%	3.42%	3.42%
Electric distribution	4.0	3.7	4.15%	4.13%	4.13%
Electric transmission	1.4	1.2	2.84%	3.07%	3.05%
Other electric	1.3	1.2	8.50%	8.70%	9.75%
Construction work in progress	0.5	0.3	NA	NA	NA
Total	$ 8.3	$ 7.5			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $0.5 billion and $1.8 billion, respectively, at December 31, 2007, and were $0.4 billion and $1.7 billion, respectively, at December 31, 2006. Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC.

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 expense and partly as a component of Other Income, Net in the Statements of Consolidated Income. AFUDC amounted to $24 million, $15 million and $12 million for 2007, 2006 and 2005, respectively.

Variable Interest Entities

FIN 46 (revised December 2003), *Consolidation of Variable Interest Entities - an interpretation of ARB No. 51* (FIN 46(R)), requires an enterprise to consolidate a variable interest entity (VIE), as defined in FIN 46(R), if the company is the primary beneficiary of a VIE’s activities.

The company has entered into a 10-year power purchase agreement with OMEC LLC for power generated at the Otay Mesa Energy Center (OMEC), a 573-megawatt (MW) generating facility currently under construction by OMEC LLC, which is expected to be in commercial operation by mid-2009. SDG&E will supply all of the natural gas to fuel the power plant. The agreement provides SDG&E the option to purchase the power plant from OMEC LLC at the end of the contract term in 2019, or upon earlier termination of the purchase power agreement, at a predetermined price subject to adjustments based on performance of the facility. If SDG&E does not exercise its option, OMEC LLC has the right, under certain circumstances, to require SDG&E to purchase the power plant at a predetermined price. As defined in FIN 46(R), OMEC LLC is a VIE, of which the company is the primary beneficiary. Accordingly, the company consolidated OMEC LLC beginning in the second quarter of 2007. The CPUC also approved an additional financial return to SDG&E to compensate it for the effect on its financial ratios from the requirement to consolidate OMEC LLC in accordance with FIN 46(R).

The company’s Consolidated Financial Statements include the following amounts associated with OMEC LLC:

(Dollars in millions)	December 31, 2007
Cash and cash equivalents	$ 1
Other current assets	3
Total current assets	4
Property, plant and equipment	232
Sundry	9
Total assets	$ 245
Accounts payable	$ 15
Other current liabilities	2
Long-term debt	70
Minority interest	135
Other	23
Total liabilities and shareholders’ equity	$ 245

(Dollars in millions)	Year ended December 31, 2007
Loss on interest-rate swaps	$ (17)
Minority interest	17
Other income, net	--
Net income	$ --

OMEC LLC has a project finance credit facility with third party lenders, secured by the assets of OMEC LLC, that provides for up to $377 million for the construction of OMEC. SDG&E is not a party to the credit agreement. The loan matures in April 2019. Borrowings under the facility bear interest at rates varying with market rates. OMEC LLC had $63 million of outstanding borrowings under this facility at December 31, 2007. In addition, OMEC LLC has entered into interest-rate swap agreements to moderate its exposure to interest-rate changes on this facility. Additional information concerning the interest-rate swaps is provided in Note 8.

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. In accordance with FIN 46(R), 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.

Asset Retirement Obligations

The company accounts for its tangible long-lived assets under SFAS 143, *Accounting for Asset Retirement Obligations* (SFAS 143), and FIN 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS 143* (FIN 47). SFAS 143 and FIN 47 require the company to record an asset retirement obligation for the present value of liabilities of future costs expected to be incurred when assets are retired from service, if the retirement process is legally required and if a reasonable estimate of fair value can be made. 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 accreting the discount until the liability is settled. Rate-regulated entities may recognize regulatory assets or liabilities as a result of the timing difference between the recognition of costs as recorded in accordance with SFAS 143 and FIN 47, and costs recovered through the rate-making process. A regulatory liability has been recorded to reflect that the company has collected the funds from customers more quickly than SFAS 143 and FIN 47 would accrete the retirement liability and depreciate the asset.

The company has recorded asset retirement obligations related to fuel storage tanks; hazardous waste storage facilities; asbestos-containing construction materials; decommissioning of its nuclear power facilities; natural gas transportation and distribution, electric distribution and electric transmission systems assets; and the site restoration of a former power plant.

The changes in asset retirement obligations for the years ended December 31, 2007 and 2006 are as follows:

(Dollars in millions)	2007	2006
Balance as of January 1*	$ 483	$ 463
Accretion expense	35	30
Liabilities incurred	1	--
Payments	(20)	(12)
Revision to estimated cash flows	69	2
Balance as of December 31*	$ 568	$ 483

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

Legal Fees

Legal fees that are associated with a past event for which a liability has been recorded are accrued when it is probable that fees also will be incurred.

In connection with charges related to litigation, the significant instances of which are discussed in Note 12, Sempra Energy management determines the allocation of the charges among its business units, including the company, based on the extent of their involvement with the subject of the litigation.

Comprehensive Income

Comprehensive income includes all changes in the equity of a business enterprise (except those resulting from investments by owners and distributions to owners), including amortization of net actuarial loss and prior service cost related to pension and other postretirement benefits plans and changes in minimum pension liability. The components of other comprehensive income, which consist of all these changes other than net income as shown on the Statements of Consolidated Income, are shown in the Statements of Consolidated Comprehensive Income and Changes in Shareholders' Equity.

The components of Accumulated Other Comprehensive Income (Loss), net of income taxes, at December 31, 2007 and 2006 are as follows:

(Dollars in millions)	2007	2006
Unamortized net actuarial loss, net of $11 and $14 income tax benefit, respectively	$ (16)	$ (20)
Unamortized prior service credit, net of $1 and $1 income tax expense, respectively	1	1
Financial instruments, net of $1 income tax benefit	(1)	--
Balance as of December 31	$ (16)	$ (19)

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 recorded under the accrual method and recognized upon delivery and performance. 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. Commodity costs associated with long-term contracts allocated to SDG&E from the DWR also are 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 revenues include amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year. The company presents its operating revenues net of sales taxes.

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

Other Operating Expenses

Other operating expenses include operating and maintenance costs, and general and administrative costs, consisting primarily of personnel costs, purchased materials and services and outside services.

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.

At December 31, 2007 and 2006, SDG&E had $22 million and $24 million, respectively, due from affiliates. These amounts are included in current assets as Due from Unconsolidated Affiliates.

SDG&E also has a promissory note due from Sempra Energy which bears a variable interest rate based on short-term commercial paper rates (4.48 percent at December 31, 2007). The balance of the note was $5 million at both December 31, 2007 and 2006, and is included in noncurrent assets as Due from Unconsolidated Affiliates.

Additionally, at December 31, 2007, SDG&E had $10 million due to affiliates, including $9 million to Sempra Energy. At December 31, 2006, SDG&E had $5 million due to affiliates, including $3 million to Sempra Energy. These amounts are included in current liabilities as Due to Unconsolidated Affiliates.

Dividends

The CPUC's regulation of the company's capital structure limits the amounts that are available for dividends and loans to Sempra Energy. At December 31, 2007, SDG&E could have provided a total of $29 million to Sempra Energy through dividends and loans.

Capitalized Interest

SDG&E recorded $10 million, $6 million and $4 million of capitalized interest for 2007, 2006 and 2005, respectively, including the portion of AFUDC related to debt.

Other Income, Net

Other Income, Net consists of the following:

(Dollars in millions)	Years ended December 31, 2007	2006	2005
Regulatory interest, net	$ (7)	$ (3)	$ (3)
Allowance for equity funds used during construction	17	10	9
Sundry, net	1	1	8
Total	$ 11	$ 8	$ 14

NOTE 2. NEW ACCOUNTING STANDARDS

Pronouncements that have recently become effective that have had or may have a significant effect on the company's financial statements are described below.

SFAS 157, "Fair Value Measurements" (SFAS 157): SFAS 157 defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. SFAS 157 does not expand the application of fair value accounting to any new circumstances. The company applies recurring fair value measurements to certain assets and liabilities, primarily nuclear decommissioning trusts and commodity and other derivatives.

SFAS 157: (1) establishes that fair value is based on a hierarchy of inputs into the valuation process (as described in Note 8), (2) clarifies that an issuer's credit standing should be considered when measuring liabilities at fair value, (3) precludes the use of a liquidity or blockage factor discount when measuring instruments traded in an actively quoted market at fair value, and (4) requires costs relating to acquiring instruments carried at fair value to be recognized as expense when incurred. SFAS 157 requires that a fair value measurement reflect the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risk inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model.

The provisions of SFAS 157 are to be applied prospectively, except for the initial impact on three specific items: (1) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, (2) existing hybrid financial instruments measured initially at fair value using the transaction price and (3) blockage factor discounts. Adjustments to these items required under SFAS 157 are to be recorded as a transition adjustment to beginning retained earnings in the year of adoption.

The company elected to early-adopt SFAS 157 in the first quarter of 2007. There was no transition adjustment as a result of the company's adoption of SFAS 157. SFAS 157 also requires new disclosures regarding the level of pricing observability associated with financial instruments carried at fair value. This additional disclosure is provided in Note 8.

SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115" (SFAS 159): SFAS 159 allows measurement at fair value of eligible financial assets and liabilities that are not otherwise measured at fair value. If the fair value option for an eligible item is elected, unrealized gains and losses for that item are reported in current earnings at each subsequent reporting date. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between the different measurement attributes the company elects for similar types of assets and liabilities. This statement is effective for fiscal years beginning after November 15, 2007. The company does not anticipate electing the fair value option at the adoption of SFAS 159 for its eligible financial assets or liabilities.

SFAS 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51" (SFAS 160): SFAS 160 amends Accounting Research Bulletin (ARB) No. 51, *Consolidated Financial Statements*, to establish accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. This statement also requires disclosures that clearly identify and distinguish between the interest of the parent and the interest of the noncontrolling owners. SFAS 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. SFAS 160 requires retroactive application for the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 shall be applied prospectively. The company is in the process of evaluating the effect of this statement on its financial position and results of operations.

SFAS 141 (revised 2007), "Business Combinations" (SFAS 141R): SFAS 141R applies to all transactions or events in which an entity obtains control of one or more businesses, including those combinations achieved without transfer or consideration. In the context of a business combination, SFAS 141R establishes principles and requirements for how the acquirer recognizes assets acquired including goodwill, liabilities assumed, noncontrolling interest in the acquiree, contractual contingencies and contingent consideration measured at fair value. SFAS 141R requires that the acquirer in a business combination achieved in stages recognize identifiable assets and liabilities at the full amounts of their fair values. This statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effect of the business combination. SFAS 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Early adoption is prohibited.

FIN 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109" (FIN 48): FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109. FIN 48 addresses how an entity should recognize, measure, classify and disclose in its financial statements uncertain tax positions that it has taken or expects to take in an income tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. Additionally, the FASB issued FASB Staff Position (FSP) FIN 48-1, *Definition of Settlement in FASB Interpretation No. 48*, which amends FIN 48 to provide guidance on how an enterprise should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The company's implementation of FIN 48 as of January 1, 2007 was consistent with the guidance in this FSP.

The company adopted the provisions of FIN 48 on January 1, 2007 and recognized a $1 million decrease in retained earnings. Including this adjustment, the company had unrecognized tax benefits of $40 million as of January 1, 2007. Of this amount, $36 million related to tax positions that, if recognized, would decrease the effective tax rate; however, $26 million related to tax positions that would increase the effective tax rate in subsequent years.

As of December 31, 2007, the company had unrecognized tax benefits of $26 million. Of this amount, $23 million related to tax positions that, if recognized, would decrease the effective tax rate; however, $22 million related to tax positions that would increase the effective tax rate in subsequent years.

A reconciliation of the company's unrecognized tax benefits from January 1, 2007 to December 31, 2007 is provided in the following table:

(Dollars in millions)		2007
Balance as of January 1, 2007	$	40
Increase in prior period tax positions		6
Decrease in prior period tax positions		(9)
Increase in current period tax positions		3
Decrease in current period tax positions		(1)
Settlements with taxing authorities		(13)
Balance as of December 31, 2007	$	26

It is reasonably possible that the company’s unrecognized tax benefits could decrease by up to $6 million within the next 12 months due to the expiration of statutes of limitations on tax assessments and by up to $4 million due to the potential resolution of audit issues with various federal and state taxing authorities.

Effective January 1, 2007, the company’s policy is to recognize accrued interest and penalties on accrued tax balances as components of tax expense. Prior to the adoption of FIN 48, the company accrued interest expense and penalties as components of tax expense and interest income as a component of interest income. As of January 1, 2007, the company had accrued a total of $7 million of such interest expense. As of December 31, 2007, the company had accrued a total of $11 million of interest benefit. The company had no accrued penalties as of either January 1, 2007 or December 31, 2007. Amounts accrued for interest expense associated with income taxes are included in income tax expense on the Statements of Consolidated Income and in various income tax balances on the Consolidated Balance Sheets.

The company is subject to U.S. federal income tax as well as income tax of state jurisdictions. The company remains subject to examination by U.S. federal and major state tax jurisdictions only for years after 2001.

In addition, the company has filed federal and state refund claims for tax years back to 1998. The pre-2002 tax years are closed to new issues; therefore, no additional tax may be assessed by the taxing authorities for these years.

NOTE 3. DEBT AND CREDIT FACILITIES

Committed Lines of Credit

SDG&E and its affiliate, SoCalGas, have a combined $600 million, five-year syndicated revolving credit facility expiring in 2010, under which each utility individually may borrow up to $500 million, subject to a combined borrowing limit for both utilities of $600 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 facility) of no more than 65 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, 2007, SDG&E had no amounts outstanding under this facility.

Weighted Average Interest Rate

The company’s weighted average interest rate on the total short-term debt outstanding was 5.36 percent at December 31, 2006.

Long-Term Debt

(Dollars in millions)	December 31, 2007		December 31, 2006	
First mortgage bonds:				
6.8% June 1, 2015	$	14	$	14
5.3% November 15, 2015		250		250
Variable rate (3.80% at December 31, 2007) July 2018		161		161
5.85% June 1, 2021		60		60
6.0% June 1, 2026		250		250
5% to 5.25% December 1, 2027		150		150
2.516% to 2.832%* January and February 2034		176		176
5.35% May 15, 2035		250		250
6.125% September 15, 2037		250		--
2.8275%* May 1, 2039		75		75
		1,636		1,386
6.37% Rate-reduction bonds, payable through 2007		--		66
Other long term:				
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
OMEC LLC project financing at 5.2925% April 2019**		63		--
OMEC LLC capitalized lease December 2033		7		--
		324		254
		1,960		1,706
Current portion of long-term debt		--		(66)
Unamortized discount on long-term debt		(2)		(2)
Total	$	1,958	$	1,638

*After floating-to-fixed rate swaps expiring in 2009.
**After floating-to-fixed rate swaps expiring in 2019.

Maturities of long-term debt are:

(Dollars in millions)		
2008	$	--
2009		--
2010		--
2011		--
2012		--
Thereafter		1,960
Total	$	1,960

Callable Long-Term Debt

At the company's option, certain debt is callable subject to premiums at various dates: $472 million in 2008, $50 million in 2010 and $274 million after 2012. In addition, $1 billion of bonds are callable subject to make-whole provisions.

In addition, the OMEC LLC project financing loan, discussed in Note 1, with $63 million of borrowings at December 31, 2007, may be prepaid at the borrower's option.

First Mortgage Bonds

First mortgage bonds are secured by a lien on 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 $2.6 billion of first mortgage bonds at December 31, 2007.

In September 2007, SDG&E sold $250 million of 6.125-percent first mortgage bonds, maturing in 2037.

Unsecured Long-Term Debt

Various long-term obligations totaling $254 million at December 31, 2007 are unsecured.

Rate-Reduction Bonds

In 2007, SDG&E redeemed the $66 million remaining outstanding balance of its rate-reduction bonds, including $17 million in September 2007 in advance of the scheduled maturity of December 26, 2007.

Interest-Rate Swaps

The company's interest-rate swaps to hedge cash flows are discussed in Note 8.

NOTE 4. FACILITIES UNDER JOINT OWNERSHIP

San Onofre Nuclear Generating Station (SONGS) and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2007 were as follows:

(Dollars in millions)	SONGS	Southwest Powerlink
Percentage ownership	20%	91%
Utility plant in service	$ 75	$ 311
Accumulated depreciation and amortization	$ 14	$ 169
Construction work in progress	$ 75	$ 2

The company, and each of the other owners, holds its interest as an undivided interest as tenants in common in the property. 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 U.S. Department of the Navy (the land owner), the CPUC and other regulatory bodies.

The asset retirement obligation related to decommissioning costs for the SONGS units was $411 million at December 31, 2007. That amount includes the cost to decommission Units 2 and 3, and the remaining cost to complete Unit 1’s decommissioning, which is currently in progress. Decommissioning cost studies are updated every three years, with the most recent update approved by the CPUC in January 2007. 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 2022.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Most 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 installation (ISFSI) licensed by the NRC. The remaining major work will include dismantling, removal and disposal of all remaining 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 will be decommissioned after a permanent storage facility becomes available and the spent fuel is removed from the site by the U.S. Department of Energy (DOE). The Unit 1 reactor vessel is expected to remain on site until Units 2 and 3 are decommissioned.

The amounts collected in rates are invested in externally managed trust funds. Amounts held by the trusts are invested in accordance with CPUC regulations. These trusts are shown on the Consolidated Balance Sheets at fair value with the offsetting credits recorded in Asset Retirement Obligations and Regulatory Liabilities Arising from Removal Obligations.

The following tables show the fair values and gross unrealized gains and losses for the securities held in the trust funds.

	As of December 31, 2007			
(Dollars in millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Debt securities				
U.S. government issues*	$ 168	$ 15	$ --	$ 183
Municipal bonds**	77	1	(2)	76
Total debt securities	245	16	(2)	259
Equity securities	204	234	(4)	434
Cash and other securities***	44	2	--	46
Total available-for-sale securities	$ 493	$ 252	$ (6)	$ 739

* Maturity dates are 2009-2038.
** Maturity dates are 2008-2057.
*** Maturity dates are 2008-2049.

	As of December 31, 2006			
(Dollars in millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Debt securities				
U.S. government issues	$ 215	$ 10	$ (1)	$ 224
Municipal bonds	55	1	--	56
Total debt securities	270	11	(1)	280
Equity securities	142	217	(1)	358
Cash and other securities	61	3	--	64
Total available-for-sale securities	$ 473	$ 231	$ (2)	$ 702

The following table shows the proceeds from sales of securities in the trust and gross realized gains and losses on those sales.

	Years ended December 31,		
(Dollars in millions)	2007	2006	2005
Proceeds from sales	$ 578	$ 474	$ 223
Gross realized gains	$ 18	$ 22	$ 17
Gross realized losses	$ (12)	$ (13)	$ (11)

Net unrealized gains are included in Asset Retirement Obligations and Regulatory Liabilities Arising from Removal Obligations on the Consolidated Balance Sheets. The company determines the cost of securities in the trust on the basis of specific identification.

The fair value of securities in an unrealized loss position as of December 31, 2007 was $79 million. The unrealized losses were primarily caused by interest-rate movements and fluctuations in the market. The company does not consider these investments to be other than temporarily impaired as of December 31, 2007.

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 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 provided in Notes 10 and 12.

NOTE 5. INCOME TAXES

Reconciliations of the U.S. statutory federal income tax rate to the effective income tax rate are as follows:

	Years ended December 31,		
	2007	2006	2005
Statutory federal income tax rate	35%	35%	35%
Depreciation	3	4	4
State income taxes, net of federal income tax benefit	5	5	6
Tax credits	(1)	(1)	(1)
Resolution of Internal Revenue Service audits	(3)	2	(13)
Regulatory reserve release	(2)	--	--
Other, net	(5)	(6)	(6)
Effective income tax rate	32%	39%	25%

The components of income tax expense are as follows:

	Years ended December 31,		
(Dollars in millions)	2007	2006	2005
Current:			
Federal	$ 131	$ 209	$ 27
State	44	73	25
Total	175	282	52
Deferred:			
Federal	(24)	(87)	39
State	(14)	(40)	1
Total	(38)	(127)	40
Deferred investment tax credits	(2)	(3)	(3)
Total income tax expense	$ 135	$ 152	$ 89

The company 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 the company's having always filed a separate return. At December 31, 2007, income taxes of $38 million were receivable from Sempra Energy.

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

(Dollars in millions)	2007	2006
Deferred tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 481	$ 477
Regulatory balancing accounts	82	160
Loss on reacquired debt	11	13
Property taxes	19	16
Other	5	8
Total deferred tax liabilities	598	674
Deferred tax assets:		
Postretirement benefits	78	101
Investment tax credits	20	22
Compensation-related items	14	16
State income taxes	21	16
Other accruals not yet deductible	27	35
Other	7	5
Total deferred tax assets	167	195
Net deferred income tax liability before valuation allowance	431	479
Valuation allowance	8	--
Net deferred income tax liability	$ 439	$ 479

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

(Dollars in millions)	2007	2006
Current asset	$ (67)	$ (41)
Noncurrent liability	506	520
Total	$ 439	$ 479

The impact of the company's adoption of FIN 48 is discussed in Note 2.

NOTE 6. EMPLOYEE BENEFIT PLANS

The company accounts for its employee benefit plans in accordance with SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106 and 132(R)* (SFAS 158), which requires an employer to recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status, measure a plan's assets and its obligations that determine its funded status as of the end of the company's fiscal year (with limited exceptions), and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. Generally, those changes are reported in the company's comprehensive income and as a separate component of shareholders' equity.

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 medical benefits for retirees' spouses.

Pension and other postretirement benefits costs and obligations are dependent on assumptions used in calculating such amounts. These assumptions include discount rates, expected return on plan assets, rates of compensation increase, health-care cost trend rates, mortality rates and other factors. These assumptions are reviewed on an annual basis prior to the beginning of each year and updated when appropriate. The company considers current market conditions, including interest rates, in making these assumptions. The company uses a December 31 measurement date for all of its plans.

Effective July 1, 2008, the company's other postretirement benefit plan will be amended to increase the health benefits for certain represented participants. This amendment resulted in a $3 million increase in the benefit obligation and unrecognized prior service costs as of December 31, 2007.

Effective January 1, 2008, the pension plan was amended to increase the death benefit for beneficiaries of vested non-represented participants that die prior to retirement. This amendment resulted in a $1 million increase in the benefit obligation and unrecognized prior service costs as of December 31, 2007.

Effective March 1, 2007, the pension plan for the company was amended to change the calculation of the benefit for certain participants. The affected participants are those who had an accrued benefit under the plan at the date the plan transitioned from a traditional defined benefit plan to a cash balance plan. The transition date was July 1, 1998 for non-represented participants, and November 1, 1998 for represented participants. Before the amendment date, these participants received the greater of their accrued benefit in the cash balance plan or the present value of their benefit under the prior plan as of June 30, 2003. After the amendment date, they receive the greater of the accrued benefit under the cash balance plan, or the present value of their accrued benefit under the prior plan at June 30, 2003 plus the cash balance benefit accrued after that date. This amendment resulted in a $29 million increase in the company's benefit obligation and in the unrecognized prior service cost at the end of 2006.

In the third quarter of 2006, the Pension Protection Act of 2006 was enacted. This act increases the funding requirements for qualified pension plans beginning in 2008. It also changes certain costs of providing pension benefits, including the interest rate for benefits paid as lump sums and the level of benefits that may be provided through qualified pension plans. The $13 million decrease in the company's pension obligation due to the plan changes required by this legislation were recognized in the benefit obligation and in the unrecognized prior service cost at the end of 2006.

Effective January 1, 2006, the pension plan for the company was amended to include deferred compensation, beginning January 1, 2006, in pension-eligible earnings. Also effective January 1, 2006, SoCalGas' pension plan for non-represented employees was amended to change the early retirement requirements. The service requirement necessary to qualify for early retirement was changed from 15 years to 10 years for participants employed by the company who were grandfathered back to SoCalGas' prior pension plan as of June 30, 2003. These two changes resulted in a net $1 million increase in the company's benefit obligation and in the unrecognized prior service cost at the end of 2006.

Effective January 1, 2006, the other postretirement benefit plans were amended to integrate the benefits plan design across the Sempra Utilities, resulting in a $52 million increase in the benefit obligation as of December 31, 2005.

The following table provides a reconciliation of the changes in the plans' projected benefit obligations and the fair value of assets during the latest two years, and a statement of the funded status as of the latest two year ends:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2007	2006	2007	2006
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	$ 842	$ 787	$ 139	$ 124
Service cost	22	12	5	5
Interest cost	47	45	8	7
Plan amendments	1	17	3	--
Actuarial loss (gain)	(29)	34	(10)	11
Transfer of liability from (to) Sempra Energy	(5)	1	--	--
Benefit payments	(75)	(54)	(6)	(8)
Net obligation at December 31	803	842	139	139
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	679	616	52	44
Actual return on plan assets	56	86	3	4
Employer contributions	27	30	15	12
Transfer of assets from (to) Sempra Energy	(3)	1	--	--
Other transfers	--	--	3	--
Benefit payments	(75)	(54)	(6)	(8)
Fair value of plan assets at December 31	684	679	67	52
Funded status at December 31	$ (119)	$ (163)	$ (72)	$ (87)
Net recorded liability at December 31	$ (119)	$ (163)	$ (72)	$ (87)

The assets and liabilities of the pension and other postretirement benefit plans are affected by changing market conditions as well as when actual plan experience is different than assumed. Such events result in gains and losses. Investment gains and losses are deferred and recognized in pension and postretirement benefit costs over a period of years. If, as of the beginning of a year, unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, the excess is amortized over the average remaining service period of active participants. The 10-percent corridor accounting method helps mitigate volatility of net periodic costs from year to year.

The net liability is included in the following captions on the Consolidated Balance Sheets at December 31 as follows:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2007	2006	2007	2006
Current liabilities	$ (1)	$ (1)	$ --	$ --
Noncurrent liabilities	(118)	(162)	(72)	(87)
Net recorded liability	$ (119)	$ (163)	$ (72)	$ (87)

Amounts recorded in Accumulated Other Comprehensive Income (Loss) as of December 31, 2007 and 2006, net of tax effects and amounts recorded as regulatory assets, are as follows:

	Pension Benefits	
(Dollars in millions)	2007	2006
Net actuarial loss	$ 16	$ 20
Prior service credit	(1)	(1)
Total	$ 15	$ 19

At December 31, 2007 and 2006, the company had an unfunded 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)	2007	2006
Projected benefit obligation	$ 774	$ 812
Accumulated benefit obligation	$ 771	$ 809
Fair value of plan assets	$ 684	$ 679

The following table provides the components of net periodic benefit cost and amounts recognized in other comprehensive income for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
(Dollars in millions)	2007	2006	2005	2007	2006	2005
Net Periodic Benefit Cost						
Service cost	$ 22	$ 12	$ 10	$ 5	$ 5	$ 3
Interest cost	47	45	42	8	7	5
Expected return on assets	(45)	(41)	(44)	(3)	(2)	(2)
Amortization of:						
Prior service cost (credit)	2	2	3	3	3	(1)
Actuarial loss	2	6	1	--	--	1
Regulatory adjustment	2	8	11	2	(1)	1
Transfer of retirees	--	--	12	--	--	(1)
Total net periodic benefit cost	30	32	35	15	12	6
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Net gain	(6)	--	--	--	--	--
Amortization of actuarial loss	(2)	--	--	--	--	--
Total recognized in other comprehensive income	(8)	--	--	--	--	--
Total recognized in net periodic benefit cost and other comprehensive income	$ 22	$ 32	$ 35	$ 15	$ 12	$ 6

The estimated net loss and prior service credit for the pension plans that will be amortized from Accumulated Other Comprehensive Income (Loss) into net periodic benefit cost in 2008 are $1 million and a negligible amount, respectively.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 establishes a prescription drug benefit under Medicare (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. The company determined that benefits provided to certain participants actuarially will be at least equivalent to Medicare Part D, and, accordingly, the company is entitled to a tax-exempt subsidy that reduced the company's accumulated postretirement benefit obligation under the plan at January 1, 2007 by $22 million and reduced the net periodic cost for 2007 by $3 million.

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

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31				
Discount rate	6.10%	5.75%	6.20%	5.85%
Rate of compensation increase	4.50%	4.50%	4.00%	4.50%
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31				
Discount rate	5.75%	5.50%	5.85%	5.60%
Expected return on plan assets	7.00%	7.00%	5.50%	4.97%
Rate of compensation increase	*	*	N/A	N/A

* 4.50% for non-qualified pension plans. Qualified plan participants use an age-based table.

The company develops the discount rate assumptions based on the results of a third party modeling tool that matches each plan's expected future benefit payments to a bond yield curve to determine their present value. It then calculates a single equivalent discount rate that produces the same present value. The modeling tool uses an actual portfolio of 500 to 600 non-callable bonds with a Moody’s Aa rating with an outstanding value of at least $50 million to develop the bond yield curve. This reflects over $300 billion in outstanding bonds with approximately 50 issues having maturities in excess of 20 years.

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.

	2007	2006
ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31		
Health-care cost trend rate *	9.48%	9.52%
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	2014 and 2016 **	2009

* This is the weighted average of the increases for the company's health plans. The rate for these plans ranged from 8.50% to 10.00% in 2006 and 2007.

** The ultimate trend rate is reached in 2014 for HMOs and 2016 for Anthem Blue Cross Plans.

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:

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

Pension Trust Investment Strategy

The asset allocation for Sempra Energy's pension trust (which includes the company's pension plan and other postretirement benefit plans, except for the plans separately described below) at December 31, 2007 and 2006 and the target allocation for 2008 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2008	2007	2006
U.S. Equity	45%	45%	46%
Foreign Equity	25	25	24
Fixed Income	30	30	30
Total	100%	100%	100%

The company's investment strategy is to stay fully invested at all times and maintain its strategic asset allocation. The equity portfolio is balanced to maintain risk characteristics similar to the Morgan Stanley Capital International (MSCI) 2500 index with respect to industry, sector and market capitalization exposures. The foreign equity portfolios are managed to track the MSCI Europe, Pacific Rim and Emerging Markets indices. Bond portfolios are managed with respect to the Lehman Aggregate Bond Index and Lehman Long Government Credit Bond Index. Other than index weight, the plan does not invest in securities of Sempra Energy.

Investment Strategy for Postretirement Health Plans

The asset allocation for the company's postretirement health plans at December 31, 2007 and 2006 and the target allocation for 2008 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2008	2007	2006
U.S. Equity	25%	25%	25%
Foreign Equity	5	5	7
Fixed Income	70	70	68
Total	100%	100%	100%

The company's postretirement health plans that are not included in the pension trust (shown above) pay premiums to health maintenance organization and point-of-service plans from company and participant contributions. The company's investment strategy is to maintain a diversified portfolio of equities and tax-exempt California municipal bonds.

Future Payments

The company expects to contribute $42 million to its pension plan and $15 million to its other postretirement benefit plans in 2008.

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.

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2008	$ 75	$ 7
2009	$ 74	$ 8
2010	$ 74	$ 9
2011	$ 75	$ 10
2012	$ 74	$ 11
2013-2017	$ 381	$ 65

The expected future Medicare Part D subsidy payments are as follows:

(Dollars in millions)	
2008-2012	$ 2
2013-2017	$ 5

Savings Plan

The company offers a trusteed savings plan to all employees. Participation in the plan is immediate for salary deferrals for all employees. Subject to plan provisions, employees may contribute from one percent to 25 percent of their regular earnings, beginning with the start of employment. After one year of each employee's 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 initially invested in Sempra Energy common stock but may be transferred by the employee into other investments. Employee contributions are invested in Sempra Energy stock, mutual funds, or institutional trusts (the same investments to which employees may direct the employer contributions) as elected by the employee. Company contributions to the savings plan were $12 million in 2007, $11 million in 2006 and $11 million in 2005.

NOTE 7. SHARE-BASED COMPENSATION

Sempra Energy has share-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 share-based awards, including non-qualified stock options, incentive stock options, restricted stock, restricted stock units, stock appreciation rights, performance awards, stock payments and dividend equivalents. Certain company employees are eligible to participate in Sempra Energy's share-based compensation plans as a component of their compensation package.

At December 31, 2007, Sempra Energy had the following types of equity awards outstanding:

- Non-Qualified Stock Options: Options have an exercise price equal to the market price of the common stock at the date of grant; are service-based; become exercisable over a four-year period (subject to accelerated vesting and/or exercisability upon a change in control, in accordance with severance pay agreements or upon retirement eligibility); and expire 10 years from the date of grant. Options are subject to forfeiture or earlier expiration upon termination of employment.

- Restricted Stock: Substantially all restricted stock vests at the end of a four-year period based on Sempra Energy's total return to shareholders relative to that of market indices (subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control, in accordance with severance pay agreements or upon retirement eligibility). Holders of restricted stock have full voting rights. They also have full dividend rights, except for company officers, whose dividends are reinvested to purchase additional shares that become subject to the same vesting conditions as the restricted stock to which the dividends relate.

Sempra Energy accounts for share-based awards in accordance with SFAS 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)), which requires the measurement and recognition of compensation expense for all share-based payment awards made to the company's employees and directors based on estimated fair values. Sempra Energy adopted the provisions of SFAS 123(R) on January 1, 2006, using the modified prospective transition method. In accordance with this transition method, Sempra Energy's consolidated financial statements for prior periods have not been restated to reflect the impact of SFAS 123(R). Under the modified prospective transition method, share-based compensation expense for 2006 includes compensation expense for all share-based compensation awards granted prior to, but for which the requisite service had not yet been performed as of January 1, 2006, based on the fair value estimated in accordance with the original provisions of SFAS 123, *Accounting for Stock-Based Compensation* (SFAS 123). Share-based compensation expense for all share-based compensation awards granted after January 1, 2006 is based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). Sempra Energy recognizes compensation costs net of an assumed forfeiture rate and recognizes the compensation costs for non-qualified stock options and restricted shares on a straight-line basis over the requisite service period of the award, which is generally four years. However, in the year that an employee becomes eligible for retirement, the remaining expense related to the employee's awards is recognized immediately. Sempra Energy estimates the forfeiture rate based on its historical experience. Sempra Energy accounts for these awards as equity awards in accordance with SFAS 123(R).

Sempra Energy subsidiaries record an expense for the plans to the extent that subsidiary employees participate in the plans and/or the subsidiaries are allocated a portion of the Sempra Energy plans' corporate staff costs. SDG&E recorded expense of $6 million, $7 million and $12 million in 2007, 2006 and 2005, respectively. Capitalized compensation cost was $2 million in each of 2007 and 2006.

NOTE 8. FINANCIAL INSTRUMENTS

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.

Cash Flow Hedges

As of both December 31, 2007 and 2006, the company has established cash flow interest-rate swap hedges for a notional amount of debt totaling $251 million. The swaps expire in 2009. In addition, OMEC LLC has entered into cash flow interest-rate swap hedges for a notional amount of debt ranging from $73 million to $377 million. The swaps expire in 2019.

In 2007, 2006 and 2005, pretax gain (loss) arising from the ineffective portion of interest-rate cash flow hedges was $(19) million (of which $(17) million applies to OMEC LLC), $(1) million and $4 million, respectively, and was recorded in Other Income, Net on the Statements of Consolidated Income.

Energy and Natural Gas Contracts

The use of derivative instruments is subject to certain limitations imposed by company policy and regulatory requirements. These instruments enable the company to estimate with greater certainty the effective prices to be received by the company and the prices to be charged to its customers. The company records realized gains or losses on derivative instruments associated with transactions for electric energy and natural gas contracts in Cost of Electric Fuel and Purchased Power and Cost of Natural Gas, respectively, on the Statements of Consolidated Income. On the Consolidated Balance Sheets, the company records corresponding regulatory assets and liabilities related to unrealized gains and losses from these derivative instruments to the extent derivative gains and losses associated with these derivative instruments will be payable or recoverable in future rates.

Fair Value of Financial Instruments

The fair values of certain of the company's financial instruments (cash, temporary investments, notes receivable, short-term debt 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:

	2007		2006	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total long-term debt*	$ 1,960	$ 1,975	$ 1,706	$ 1,717
Preferred stock	$ 93	$ 90	$ 96	$ 97

* Before reductions for unamortized discount of $2 million at both December 31, 2007 and 2006.

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

Adoption of SFAS 157

Effective January 1, 2007, the company early-adopted SFAS 157 as discussed in Note 2, which, among other things, requires enhanced disclosures about assets and liabilities carried at fair value.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under SFAS 157, the company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The company primarily applies the market approach for recurring fair value measurements and endeavors to utilize the best available information. Accordingly, the company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The company is able to classify fair value balances based on the observability of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

> Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.
>
> Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.
>
> Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value. At each balance sheet date, the company performs an analysis of all instruments subject to SFAS 157 and includes in level 3 all of those whose fair value is based on significant unobservable inputs.

The following table sets forth by level within the fair value hierarchy the company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2007. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Recurring Fair Value Measures	At fair value as of December 31, 2007			
(Dollars in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ 18	$ 3	$ --	$ 21
Nuclear decommissioning trusts	551	175	--	726
Other derivatives	--	--	7	7
Total	$ 569	$ 178	$ 7	$ 754
Liabilities:				
Commodity derivatives	$ 9	$ 8	$ --	$ 17
Other derivatives	--	20	--	20
Total	$ 9	$ 28	$ --	$ 37

Nuclear decommissioning trusts reflect the assets of the company's nuclear decommissioning trusts, excluding cash balances, as discussed in Note 4. Commodity derivatives include commodity and other derivative positions entered into to manage customer price exposures, and other derivatives include interest-rate management instruments. The following table sets forth a reconciliation of changes in the fair value of net other derivatives classified as level 3 in the fair value hierarchy:

(Dollars in millions)	2007
Balance as of January 1, 2007	$ --
Allocated transmission instruments	7
Balance as of December 31, 2007	$ 7
Change in unrealized gains (losses) relating to instruments still held as of December 31, 2007	$ 7

During the third quarter of 2007, the California Independent System Operator (ISO) began the process of allocating congestion revenue rights (CRRs) to load serving entities, including SDG&E. These instruments are considered derivatives and are recorded at fair value based on discounted cash flows. They are classified as level 3 and reflected in the table above. As of December 31, 2007, changes in the fair value of CRRs, which are valued at $7 million, will be deferred and recorded in regulatory accounts to the extent they are recoverable through rates.

NOTE 9. PREFERRED STOCK

	Call/ Redemption Price	December 31, 2007	December 31, 2006
Not subject to mandatory redemption:		(in millions)	
$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	$ 25.595	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, 550,000 and 650,000 shares outstanding at December 31, 2007 and 2006, respectively	$ 25.00	$ 14	$ 17

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. 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. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share in 2007 and all remaining shares in 2008. On January 15, 2007 and January 15, 2008, SDG&E redeemed 100,000 shares and 550,000 shares, respectively.

SDG&E is currently authorized to issue up to 25 million shares of an additional class of preference shares designated as "Series Preference Stock." The Series Preference Stock is in addition to the Cumulative Preferred Stock, Preference Stock (Cumulative) and Common Stock that the company was otherwise authorized to issue, and when issued would rank junior to the Cumulative Preferred Stock and Preference Stock (Cumulative) and have rights, preferences and privileges that would be established by the board at the time of issuance.

NOTE 10. ELECTRIC INDUSTRY REGULATION

Background

One legislative response to the 2000 - 2001 energy 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 among the IOUs of the power and its administrative responsibility, including collection of power contract costs from utility customers. 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 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, commodity costs associated with long-term contracts allocated to SDG&E from the DWR (and the revenues to recover those costs) are not included in the Statements of Consolidated Income.

Power Procurement and Resource Planning

Effective in 2003, the CPUC directed the IOUs to resume electric commodity procurement to cover their net short energy requirements and also implemented legislation regarding procurement and renewable energy 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.

Sunrise Powerlink Electric Transmission Line

SDG&E has applied to the CPUC for authorization to construct the Sunrise Powerlink, a 500-kV electric transmission line between the Imperial Valley and the San Diego region that will be able to deliver 1,000 MW. The project, as proposed, is estimated to cost $1.3 billion, which includes AFUDC related to both debt and equity. In November 2007, the Imperial Irrigation District, which had entered into a Memorandum of Agreement with the company to cooperatively build the project subject to the negotiation of a definitive agreement, decided not to participate in the project.

Phase I evidentiary hearings covering project need were completed in October 2007, and the Administrative Law Judge (ALJ) directed parties to submit Phase I opening and reply briefs, which were filed on November 9, 2007 and November 30, 2007, respectively.

In January 2008, the CPUC issued a draft Environmental Impact Report (EIR) and Environmental Impact Study (EIS) for public comment and will hold additional workshops and public participation hearings in response to their findings. Comments on the draft EIR/EIS are due in April 2008. Among other things, the draft EIR/EIS finds that a combination of in-basin conventional fossil fuel generation and renewable generation is the environmentally superior alternative when analyzed entirely from an environmental impact standpoint. The environmental analysis is one of many studies the CPUC will evaluate in its overall project assessment. Phase II evidentiary hearings have been scheduled for April 2008 to address environmental issues associated with the project, including alternative project and route proposals. The final EIR/EIS is scheduled to be issued by June 2008. A final CPUC decision on the project, which will consider the environmental, technical and economic attributes of the various alternatives, is expected in the second half of 2008.

Given this timeline, if the project is approved by the CPUC as proposed in the company's original filings, the earliest management projects the Sunrise Powerlink would be in commercial operation would be in the first half of 2011.

Renewable Energy

California Senate Bill 107 (SB 107), enacted in September 2006, requires certain California electric retail sellers, including the company, to achieve a 20-percent renewable energy portfolio by 2010. The rules governing this requirement, administered by both the CPUC and the California Energy Commission, are generally known as the Renewable Portfolio Standards (RPS).

At the end of December 2007, SDG&E has renewable energy supply under contract of approximately 13 percent of its projected 2010 retail demand. A substantial portion of these contracts, however, are contingent upon many factors, including access to electric transmission infrastructure (including SDG&E's proposed Sunrise Powerlink transmission line), timely regulatory approval of contracted renewable energy projects, the renewable energy project developers' ability to obtain project financing, and successful development and implementation of the renewable energy technologies.

Given the revised Sunrise Powerlink EIR/EIS timeline, as discussed above, the Sunrise Powerlink transmission line, if approved, will not be in operation to provide transmission capability to meet the RPS requirements by the 2010 deadline. Consequently, the company believes it is unlikely that it will be able to meet the 2010 delivered-energy goal as contained in the RPS. The company's failure to attain the 20-percent goal in 2010, or in any subsequent year, could subject it to a CPUC-imposed penalty, subject to flexible compliance measures, of 5 cents per kilowatt hour of renewable energy under-delivery up to a maximum penalty of $25 million per year under the current rules. In January 2008, the CPUC issued a proposed decision defining the flexible compliance mechanisms that can be used in meeting the RPS goals in 2010 and beyond, including clarifying rules within which insufficient transmission is a permissible reason for failing to satisfy the RPS goals. While the company believes it will be able to comply with the RPS requirements based on its contracting activity and application of the flexible compliance mechanisms, the company is unable to predict whether it will be penalized or the amount that would be imposed.

Greenhouse Gas Regulation

Legislation was enacted in 2006, including California Assembly Bill 32 (AB 32) and California Senate Bill 1368 (SB 1368), mandating reductions in greenhouse gas emissions, which could affect costs and growth at SDG&E. Any cost impact is expected to be recoverable through rates.

Long-Term Procurement Plan

SDG&E filed its long-term procurement plan (LTPP) with the CPUC in December 2006, including a ten-year energy resource plan that details its expected portfolio of energy resources over the planning horizon of 2007 - 2016. The LTPP incorporates the renewable energy and greenhouse gas emissions performance standards established by the CPUC and by AB 32, SB 107 and SB 1368. SDG&E's LTPP identifies, among other details, the need for additional system generation resources beginning in 2010, including a baseload plant in 2012. A final CPUC decision was issued in December 2007 adopting the various elements of the SDG&E LTPP. Consistent with its LTPP, SDG&E separately filed an application with the CPUC in August 2007 seeking authority to exercise its option to acquire, in 2011, the El Dorado power plant from Sempra

Generation (a business unit of Sempra Energy) at Sempra Generation's net book value on the date of acquisition, estimated to be $189 million, as part of a settlement described in Note 12 under "Other Natural Gas Cases." The CPUC and the FERC approved SDG&E's request to exercise its option to acquire the El Dorado power plant in 2011 in November 2007 and February 2008, respectively.

San Onofre Nuclear Generating Station (SONGS)

In June 2006, the CPUC adopted a decision granting SDG&E an increase in SONGS' electric rate revenues for 2004 and 2005, which resulted in a $13.2 million increase in pretax income in the second quarter of 2006. This decision resolved a computational error in the CPUC's 2004 Cost of Service decision which established the revenue requirement for SDG&E's share of the operating costs of SONGS.

In May 2006, the CPUC adopted a decision in the 2006 General Rate Case for Southern California Edison (Edison), the operator of SONGS, which authorized for SDG&E a $21.8 million increase in its revenue requirement for 2006.

In 2004, Edison applied for CPUC approval to replace the steam generators at SONGS, stating that the work needed to be done in 2009 and 2010 for Units 2 and 3, respectively, and would require an estimated capital expenditure of $680 million (in 2004 dollars). SDG&E's share of the estimated capital investment, in 2004 dollars, is $136 million. During 2006, SDG&E, Edison and the CPUC's Division of Ratepayer Advocates (DRA) reached a settlement, which was subsequently approved by the CPUC, supporting SDG&E's participation in the replacement project as well as providing SDG&E with full recovery of current operating and maintenance costs via balancing account treatment effective January 1, 2007.

Spent Nuclear Fuel

SONGS owners have responsibility for the interim storage of spent nuclear fuel generated at SONGS until it is accepted by the DOE for final disposal. Spent nuclear fuel has been stored in the SONGS Units 1, 2 and 3 spent fuel pools and in the ISFSI. Movement of all Unit 1 spent fuel to the ISFSI was completed as of December 31, 2005. Spent fuel for Unit 2 is being stored in both the Unit 2 spent fuel pool and the ISFSI. Spent fuel for Unit 3 is being stored in the spent fuel pool, with storage in the ISFSI scheduled to begin in 2008. Construction of a second ISFSI pad was initiated in the second half of 2007 and will provide sufficient storage capacity through 2022.

Electric Transmission Formula Rate

Effective July 1, 2007, SDG&E will recover its annual transmission capital investment at a return on equity (ROE) of 11.35 percent, an increase from the previous authorized ROE of 11.25 percent, which equates to an estimated annualized revenue increase in 2008 of $18 million. SDG&E also renewed its annual transmission formula rate, with only slight modifications from the previous formula, for six years from July 1, 2007 through August 31, 2013.

Advanced Metering Infrastructure

In April 2007, the CPUC approved SDG&E's initiative to install advanced meters with integrated two-way communications functionality, providing for remote disconnect and a home area network for all customers. SDG&E estimates expenditures for this project of $572 million (including approximately $500 million in capital investment), which involves the replacement of 1.4 million electric and 900,000 natural gas meters throughout SDG&E's service territory. The meter replacements are anticipated to commence in the fourth quarter of 2008 and be completed by early 2011.

NOTE 11. OTHER REGULATORY MATTERS

General Rate Case (GRC)

In April 2007, the company filed an amendment to its original 2008 General Rate Case application (2008 GRC) as filed in December 2006 with the CPUC. The 2008 GRC application, as amended, establishes the 2008 authorized margin requirements and the ratemaking mechanisms by which those margin requirements would change annually effective in 2009 through 2013 (2008 GRC rate period).

As part of the General Rate Case process, applications are subject to review and testimony by various groups representing the interests of ratepayers and other constituents. In December 2007, the company filed with the CPUC a settlement agreement reached in principle with the DRA and Aglet Consumer Alliance. If approved, the settlement would provide a 2008 revenue requirement of $1.349 billion and would resolve all 2008 revenue requirement issues. Comments were submitted in January 2008. If adopted, the settlement represents an increase in the annual authorized margin in 2008 of $138 million, as compared to 2007 authorized margin. The company also reached a settlement agreement with the DRA, The Utility Reform Network (TURN) and Aglet Consumer Alliance regarding post test-year provisions including the term of the GRC period, earnings sharing and the year-to-year attrition allowances during the GRC period. As part of the settlement, the parties agreed to a GRC term of four years (2008 through 2011) with the DRA separately agreeing to a term of five years (through 2012). The parties also agreed to post test-year revenue requirement increases in fixed dollar amounts (i.e., no escalation, true-up or after-the-fact modification) as follows: $41 million for 2009, $44 million for 2010 and $44 million for 2011. The DRA separately agreed to revenue requirement increases of $45 million for 2012. These amounts exclude any CPUC-approved revenue requirements or rate base changes that are outside the scope of the GRC (e.g., Cost of Capital). The parties also agreed that there would be no earnings sharing between the company and ratepayers should the company exceed the authorized return on equity for any year in the post test-year period. The settlement was filed with the CPUC on January 18, 2008, and parties have an opportunity to comment on the filing.

The company has filed a request with the CPUC to make any decision on the 2008 GRC effective retroactive to January 1, 2008. In December 2007, the CPUC issued a decision allowing SDG&E to establish regulatory memorandum accounts to record any difference between their current and future adopted revenue requirements on and after January 1, 2008 until a final decision is issued. This would enable the company to recover or refund these amounts in the future. However, the decision asks parties to comment on the extent to which SDG&E may have improperly caused a delay in the proceeding and to what extent, if any, these recorded amounts should be reduced as a result. A final CPUC decision on all GRC Phase I issues is expected in the second quarter of 2008.

Phase II of this proceeding, which deals with cost allocation among customer classes, began with public hearings in early September 2007. The GRC Phase II filing proposes a number of demand response and energy conservation initiatives for all customer classes, with incentives for reduced electricity usage. The filing also proposes the gradual elimination of residential rate caps that have been required by state legislation since the California energy crisis in 2001. An all-party settlement agreement was reached and filed with the CPUC in October 2007. The settlement agreement resolves all issues in the proceeding, except SDG&E's proposal to gradually eliminate residential rate caps. On January 29, 2008, the ALJ issued a proposed decision adopting the settlement agreement. A final decision on the settlement agreement is expected to be issued in early 2008. Opening briefs on the proposal to gradually eliminate residential rate caps were filed in December 2007 and reply briefs in January 2008. A CPUC decision on that proposal is expected to be issued by mid-2008.

Cost of Capital Proceeding

The company filed an application with the CPUC in May 2007 seeking to update its cost of capital, authorized ROE and debt/equity ratios. In December 2007, the CPUC issued a final decision increasing the company's authorized ROE from 10.7 percent to 11.1 percent effective January 1, 2008, and maintaining the company's current capital structure of 49 percent common equity, 5.75 percent preferred equity and 45.25 percent long-term debt. As a result, SDG&E's authorized return on rate base will be 8.40 percent effective January 1, 2008.

Utility Ratemaking Incentive Awards

Performance-Based Regulation (PBR) consists of a series of measures of utility performance. Generally, if performance is outside of a band around specified benchmarks, the utility is rewarded or penalized certain dollar amounts. The three areas that are eligible for incentive awards or penalties are PBR operational incentives, which measure safety, reliability and customer service; energy efficiency (sometimes referred to as demand-side management, or DSM or EE) awards based on the effectiveness of the energy efficiency programs; and natural gas procurement awards or penalties. The operational PBR incentives and the associated benchmarks are determined as a component of a general rate case or cost of service decision. The operational PBR incentives to be in effect for fiscal year 2008 through the end of the 2008 GRC rate period are under consideration as part of the 2008 GRC. The company has recommended continuing the PBR measures in effect through 2007 with slight modifications to the benchmarks. The company expects a final CPUC decision on this issue in the second quarter of 2008.

The company's PBR for natural gas procurement awards or penalties will end on the effective date of the combination of the core natural gas supply portfolios as discussed below under "Omnibus Gas Settlements."

PBR and DSM awards are not included in the company's earnings until CPUC approval of each award is received. All awards discussed below are on a pretax basis.

Operational PBR and Natural Gas Procurement

During the year ended December 31, 2007, SDG&E's pretax earnings included $11 million related to PBR awards.

Energy Efficiency

In September 2007, the CPUC established a mechanism to financially reward or penalize the IOUs for their performance on post-2005 energy-efficiency programs. The mechanism rewards or penalizes the IOUs based upon specific portfolio performance goals to reduce energy consumption by its customers. The program provides for three-year cycles, with the first three-year cycle covering 2006 through 2008. The company's maximum rewards and penalties for the three-year program period, on a pretax basis, are $50 million. Generally, the company will be entitled to rewards when the energy cost savings are 85-125 percent of goal. The company is subject to penalties when the savings are less than 65 percent of goal, with the maximum penalty reached when savings are 35 percent of goal. No incentive or penalty applies for performance between 65-85 percent.

In January 2008, the CPUC issued a decision modifying the measurement and verification process of this earnings mechanism, which will enhance the predictability of earnings (or penalties) from energy efficiency programs. The company expects to file its initial report on its 2006 and 2007 energy efficiency results as compared to goal with the CPUC in the second quarter of 2008, with a decision anticipated by the end of 2008.

Omnibus Gas Settlements

In August 2006, SoCalGas, SDG&E and Edison jointly filed an application with the CPUC seeking its approval of a series of revisions to the natural gas operations and service offerings of the Sempra Utilities. The proposals resulted from the successful resolution of various litigation matters related to the 2000 - 2001 energy crisis. The CPUC issued a final decision in December 2007 approving some, but not all, of the proposals and deferring a number of issues to the Sempra Utilities' next Biennial Cost Allocation Proceeding (BCAP), which is scheduled to begin in February 2008. As part of the decision, the natural gas supply portfolios for SDG&E's and SoCalGas' core customers will be combined into a single natural gas supply portfolio to be administered by SoCalGas effective April 1, 2008. All SDG&E assets associated with its core natural gas supply portfolio will be transferred or assigned to SoCalGas, which will be responsible for meeting the needs of both SDG&E's and SoCalGas' core natural gas customers at the same core gas monthly price. As a result, effective April 1, 2008, SDG&E will no longer be subject to its own gas procurement PBR mechanism. SDG&E and SoCalGas filed a joint BCAP application with the CPUC in February 2008, seeking a decision by year-end 2008.

Natural Gas Market OIR

The CPUC considered natural gas market issues, including market design and infrastructure requirements, as part of its Natural Gas Market Order Instituting Rulemaking (OIR). A final decision in Phase II of this proceeding was issued in September 2006, reaffirming the adequacy of the capacity of the SoCalGas and SDG&E systems to meet current demand. In particular, this decision established natural gas quality standards that would permit the introduction of regasified liquefied natural gas (LNG) supplies into California's natural gas distribution system. The South Coast Air Quality Management District and the City of San Diego (jointly with Ratepayers for Affordable Clean Energy) have filed petitions for review in the California Court of Appeal and the California Supreme Court challenging the CPUC's September 2006 decision and contending that the California Environmental Quality Act (CEQA) applies to the changes in natural gas quality standards approved by the CPUC, and that impacts on the environment should be fully considered. In November 2007, the Court of Appeal determined that the California Supreme Court has exclusive jurisdiction to consider a CEQA challenge to a CPUC decision. A decision by the California Supreme Court is expected by the end of 2008.

Gain On Sale Rulemaking

In May 2006, the CPUC adopted a decision standardizing the treatment of gains and losses on future sales of utility property. It provided for an allocation of 100 percent of the gains and losses from depreciable property to ratepayers and a 50/50 allocation of gains and losses from non-depreciable property between ratepayers and shareholders. Under certain circumstances, the CPUC would be able to depart from the standard allocation. The DRA and TURN filed a joint request for rehearing of the decision requesting, among other things, that the CPUC adopt a 90/10 allocation of gains from non-depreciable assets between ratepayers and shareholders. In December 2006, the CPUC denied the request for rehearing, but modified its prior decision revising the allocation between ratepayers and shareholders to 67/33. In July 2007, the CPUC issued a resolution which adopted a gross-up formula for calculating the ratepayers' allocation of taxes associated with any gains or losses from the sale of utility assets.

Southern California Wildfires

In October 2007, major wildfires throughout Southern California destroyed many homes, damaged utility infrastructure and disrupted utility services. On October 21, 2007, Governor Arnold Schwarzenegger declared a state of emergency for seven California counties, including the county of San Diego and six counties within SoCalGas' service territory. With a declaration of a state of emergency, the Sempra Utilities can request recovery of any material incremental costs of restoring utility services and utility facilities damaged by the wildfires in cost recovery proceedings applicable to disaster events. In December 2007, the company notified the CPUC of its intent to request recovery of the incremental costs incurred by SDG&E in response to the wildfires and has established the necessary regulatory accounts to record these costs. SDG&E currently estimates that the total incremental costs incurred associated with the CPUC and FERC regulated operations, primarily capital-related, will range from $45 million to $55 million and $15 million to $25 million, respectively. The application for cost recovery is expected to be filed with the CPUC in the second quarter of 2008. Additional information regarding the Southern California Wildfires is provided in Note 12.

NOTE 12. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

At December 31, 2007, the company’s reserves for litigation matters were $39 million, of which $37 million related to settlements reached to resolve certain litigation arising out of the 2000 – 2001 California energy crisis. The uncertainties inherent in complex legal proceedings make it difficult to estimate with any degree of certainty the costs and effects of resolving legal matters. Accordingly, costs ultimately incurred may differ materially from estimated costs and could materially adversely affect the company's business, cash flows, results of operations and financial condition.

Sempra Commodities, Sempra Generation and Sempra LNG, referred to in the following discussion, are business units of Sempra Energy.

Continental Forge Settlement

The litigation that is the subject of the settlements and $37 million of reserves is frequently referred to as the Continental Forge litigation, although the settlements also include other cases. The Continental Forge class-action and individual antitrust and unfair competition lawsuits in California and Nevada alleged that Sempra Energy and the Sempra Utilities unlawfully sought to control natural gas and electricity markets and claimed damages in excess of $23 billion after applicable trebling.

The San Diego County Superior Court entered a final order approving the settlement of the Continental Forge class-action litigation as fair and reasonable in July 2006. The California Attorney General and the DWR have appealed the final order. Oral argument is expected to take place in 2008. The Nevada Clark County District Court entered an order approving the Nevada class-action settlement in September 2006. Both the California and Nevada settlements must be approved for either settlement to take effect, but Sempra Energy is permitted to waive this condition. The settlements are not conditioned upon approval by the CPUC, the DWR, or any other governmental or regulatory agency.

To settle the California and Nevada litigation, in January 2006, Sempra Energy agreed to make cash payments in installments aggregating $377 million, of which $347 million relates to the Continental Forge and California class action price reporting litigation and $30 million relates to the Nevada antitrust litigation. The Los Angeles City Council had not previously voted to approve the City of Los Angeles' participation in the January 2006 California settlement. In March 2007, Sempra Energy and the Sempra Utilities entered into a separate settlement agreement with the City of Los Angeles resolving all of its claims in the Continental Forge litigation in return for the payment of $8.5 million in April 2007. This payment was made in lieu of the $12 million payable in eight annual installments that the City of Los Angeles was to receive as part of the January 2006 California settlement.

Additional consideration for the January 2006 California settlement includes an agreement that Sempra LNG would sell to the Sempra Utilities, subject to CPUC approval, regasified LNG from its LNG terminal being constructed in Baja California, Mexico, for a period of 18 years at the California border index price minus $0.02 per million British thermal units (MMBtu). Also, Sempra Generation voluntarily would reduce the price that it charges for power and limit the locations at which it would deliver power under its DWR contract. Based on the expected contractual power deliveries, this discount would have potential value aggregating $300 million over the contract's then remaining six-year term.

Under the terms of the January 2006 settlements, $83 million was paid in August 2006 and an additional $83 million was paid in August 2007. Of the remaining amounts, $25.8 million is to be paid on the closing date of the January 2006 settlements, which will take place after the resolution of all appeals, and $24.8 million will be paid on each successive anniversary of the closing date through the seventh anniversary of the closing date, as adjusted for the City of Los Angeles settlement. Under the terms of the City of Los Angeles settlement, $8.5 million was paid in April 2007. The reserves recorded for the California and Nevada settlements by Sempra Energy, including SDG&E, in 2005 fully provide for the present value of both the cash amounts to be paid in the settlements and the price discount to be provided on electricity to be delivered under the DWR contract. A portion of the reserves was discounted at 7 percent, the rate specified for prepayments in the settlement agreement. For payments not addressed in the agreement and for periods from the settlement date through the estimated date of the first payment, 5 percent was used to approximate Sempra Energy's average cost of financing.

Other Natural Gas Cases

In 2005, the California Attorney General and the CPUC filed a lawsuit in San Diego County Superior Court alleging that in 1998 Sempra Energy and the Sempra Utilities intentionally misled the CPUC, resulting in insufficient utility pipeline capacity, curtailment of natural gas service to electric generators and others, and the ensuing increase in air pollution and electricity prices for California consumers from the use of oil as an alternate fuel source. In September 2006, the parties entered into a settlement that required the Sempra Utilities to pay $2 million for attorneys' fees and costs incurred by the California Attorney General, SDG&E to be given the option to purchase Sempra Generation's El Dorado power plant in 2011 for book value subject to FERC approval, and Sempra Energy to pay approximately $5.7 million to SDG&E electricity customers beginning in 2009 to reduce SDG&E's electric procurement costs. The CPUC and the FERC approved the company’s request to exercise its option to acquire the El Dorado power plant in 2011 in November 2007 and February 2008, respectively.

In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in the U.S. District Court in Nevada against major natural gas suppliers, including Sempra Energy, the Sempra Utilities and Sempra Commodities, seeking recovery of damages alleged to aggregate in excess of $150 million (before trebling). The lawsuit alleges a conspiracy to manipulate and inflate the prices that Nevada Power had to pay for its natural gas by preventing the construction of natural gas pipelines to serve Nevada and other Western states, and reporting artificially inflated prices to trade publications. The U.S. District Court dismissed the case in November 2004, determining that the FERC had exclusive jurisdiction to resolve the claims. In September 2007, the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit Court of Appeals) reversed the dismissal and returned the case to the District Court for further proceedings.

Apart from the claims settled in connection with the Continental Forge settlement, the remaining 13 state antitrust actions that were coordinated in San Diego Superior Court against Sempra Energy, the Sempra Utilities and Sempra Commodities and other, unrelated energy companies, alleging that energy prices were unlawfully manipulated by the reporting of artificially inflated natural gas prices to trade publications and by entering into wash trades and churning transactions, were settled on January 4, 2008, for $2.5 million.

Pending in the U.S. District Court in Nevada are five cases against Sempra Energy, Sempra Commodities, the Sempra Utilities and various other companies, which make similar allegations to those in the state proceedings, four of which also include conspiracy allegations similar to those made in the Continental Forge litigation. The court dismissed four of these actions, determining that the FERC had exclusive jurisdiction to resolve the claims. The remaining case, which includes conspiracy allegations, was stayed. In September 2007, the Ninth Circuit Court of Appeals reversed the dismissal and these cases are expected to return to the District Court for further proceedings.

FERC Refund Proceedings

The FERC is investigating prices charged to buyers in the California Power Exchange (PX) and ISO markets by various electric suppliers. In December 2002, a FERC ALJ issued preliminary findings indicating that the 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). In March 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, which would increase the refund obligations from $1.8 billion to more than $3 billion for the same time period.

Various parties appealed the FERC's order to the Ninth Circuit Court of Appeals. In August 2006, the Court of Appeals held that the FERC had properly established October 2, 2000 through June 20, 2001 as the refund period and had properly excluded certain bilateral transactions between sellers and the DWR from the refund proceedings. However, the court also held that the FERC erred in excluding certain multi-day transactions from the refund proceedings. Finally, while the court upheld the FERC's decision not to extend the refund proceedings to the summer period (prior to October 2, 2000), it found that the FERC had erred in not considering other remedies, such as disgorgement of profits, for tariff violations that are alleged to have occurred prior to October 2, 2000. The Court of Appeals remanded the matter to the FERC for further proceedings. In November 2007, Sempra Commodities and other entities filed requests for rehearing of the Court of Appeals' August 2006 decision. In August 2007, the Ninth Circuit Court of Appeals issued a decision reversing and remanding FERC orders declining to provide refunds in a related proceeding regarding short-term bilateral sales up to one month in the Pacific Northwest. The court found that some of the short-term sales between the DWR and various sellers (including Sempra Commodities) that had previously been excluded from the refund proceeding involving sales in the ISO and PX markets in California, were within the scope of the Pacific Northwest refund proceeding. In December 2007, Sempra Commodities and other sellers filed requests for rehearing of the Court of Appeals' August 2007 decision. It is possible that on remand, the FERC could order refunds for short-term sales to the DWR in the Pacific Northwest refund proceeding.

SDG&E has been awarded $171 million through December 31, 2007, in settlement of certain claims against electricity suppliers related to the 2000 - 2001 California energy crisis. The net proceeds of these settlements are for the benefit of ratepayers and for the payment of third party fees associated with the recovery of these claims. Of the $171 million, all monies have been received by SDG&E, except for $10 million pending FERC approval.

Other Litigation

In October 2007, Southern California experienced catastrophic wildfires. The causes of many of these fires remain under investigation, including the possible role of SDG&E power lines affected by unusually high winds. In November 2007, the California Department of Forestry and Fire Protection (Cal Fire) issued a press release stating that power lines caused three of the fires in San Diego County and that together these three fires burned more than 200,000 acres and destroyed approximately 1,900 structures. Cal Fire is expected to issue a final report, and the CPUC's Consumer Protection and Safety Division, which is also investigating the fires, is also expected to issue a report. Five lawsuits, four of which seek to be designated as class actions, have been filed against SDG&E in San Diego County Superior Court seeking unspecified amounts for damages relating to the fires. The lawsuits assert that SDG&E improperly designed and maintained its power lines and failed to adequately clear adjacent vegetation. The company has in excess of $1 billion in liability insurance and has notified its insurers of the lawsuits.

Natural Gas Contracts

SDG&E buys natural gas under short-term contracts. Purchases are from various southwestern U.S., U.S. Rockies and Canadian suppliers and are primarily based on monthly spot-market prices. The company transports natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. Note 11 discusses the CPUC's Natural Gas Market OIR.

SDG&E has natural gas transportation contracts with various interstate pipelines that expire on various dates between 2008 and 2023. SDG&E currently purchases natural gas on a spot basis from Canada, the U.S. Rockies, and the southwestern United States to fill its long-term pipeline capacity, and purchases additional spot-market supplies delivered directly to California for its remaining requirements.

All of SDG&E's natural gas is delivered through SoCalGas' pipelines under a long-term transportation agreement. In addition, under separate agreements expiring in March 2008, SoCalGas provides SDG&E up to nine billion cubic feet (Bcf) of storage capacity. Pursuant to a CPUC decision issued in December 2007, the responsibility for procuring gas for both SDG&E's and SoCalGas' core customers will be combined into a single natural gas supply portfolio to be administered by SoCalGas effective April 1, 2008. All SDG&E assets associated with their core natural gas supply portfolio will be transferred or assigned to SoCalGas, which will be responsible for meeting the needs of both SDG&E's and SoCalGas' core natural gas customers at the same core gas monthly price.

At December 31, 2007, the future minimum payments under existing natural gas storage and transportation contracts were:

(Dollars in millions)	
2008	$ 26
2009	16
2010	13
2011	13
2012	13
Thereafter	109
Total minimum payments	$ 190

Total payments under natural gas contracts were $390 million in 2007, $380 million in 2006 and $455 million in 2005. Upon the combination of the company's and SoCalGas' core natural gas portfolios, these commitments will be assigned or transferred to SoCalGas.

Purchased-Power Contracts

For 2008, SDG&E expects to receive 27 percent of its customer power requirements from DWR allocations. Of the remaining requirements, SONGS is expected to account for 19 percent, long-term contracts for 17 percent (of which 6 percent is provided by renewable energy contracts expiring on various dates through 2025), other SDG&E-owned generation (including Palomar) and tolling contracts for 19 percent and spot market purchases for 18 percent. The long-term contracts expire on various dates through 2033.

At December 31, 2007, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)	
2008	$ 360
2009	421
2010	343
2011	345
2012	335
Thereafter	2,536
Total minimum payments	$ 4,340

The payments represent capacity charges and minimum energy purchases. The company 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 $351 million in 2007, $344 million in 2006 and $363 million in 2005.

Leases

The company has operating leases on real and personal property expiring at various dates from 2008 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 4 percent to 5 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options that are exercisable by the company. Rent expense totaled $24 million in 2007, $23 million in 2006 and $22 million in 2005. At December 31, 2007, the minimum rental commitments payable in future years under all noncancelable leases were as follows:

(Dollars in millions)	
2008	$ 22
2009	22
2010	20
2011	19
2012	17
Thereafter	63
Total future rental commitments	$ 163

Guarantees

As of December 31, 2007, the company did not have any outstanding guarantees.

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 costs 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.

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. 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, and must spend significant sums on environmental monitoring, pollution control equipment, mitigation costs and emissions fees. 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 generally capitalized. The company's capital expenditures to comply with environmental laws and regulations were $11 million in 2007, $14 million in 2006 and $9 million in 2005. 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 probability 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, 2007 and one to be completed, including one site reopened during 2007), cleanup of third-party waste-disposal sites used by the company, which has been identified as a PRP (investigations and remediations continuing and one site completed) 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 at undiscounted amounts 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. Not including the liability for SONGS marine mitigation, which SDG&E is participating in jointly with Edison, at December 31, 2007, the company's accrued liability for environmental matters was $6.4 million, of which $0.1 million is related to manufactured-gas sites, $6 million to cleanup at SDG&E's former fossil-fueled power plants, $0.2 million to waste-disposal sites used by the company (which has been identified as a PRP) and $0.1 million to other hazardous waste sites. The majority of these accruals are expected to be paid over the next two years. In connection with the issuance of operating permits, SDG&E and the other owners of SONGS previously reached an 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. At December 31, 2007, the estimated amount remaining to be spent by SDG&E through 2050 is $11 million, which is recoverable in rates.

Nuclear Insurance

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. The insurance provides coverage of $300 million, the maximum amount available. In addition, the Price-Anderson Act provides for up to $10.5 billion of secondary financial protection. Should any of the licensed/commercial reactors in the United States experience a nuclear liability loss that exceeds the $300 million insurance limit, all utilities owning nuclear reactors could be assessed to provide the secondary financial protection. SDG&E's total share would be up to $40 million, subject to an annual maximum assessment of $6 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, SDG&E could be subject to an additional assessment.

SDG&E and the other owners of SONGS have $2.75 billion of nuclear property, decontamination and debris removal insurance and up to $490 million for outage expenses and replacement power costs 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, after a waiting period of 12 weeks. The insurance is provided through a mutual insurance company, through which insured members are subject to retrospective premium assessments (up to $8.6 million in SDG&E's case).

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. There are industry aggregate limits of $300 million for liability claims and $3.24 billion for property claims, including replacement power costs, for non-certified acts of terrorism. 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.

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 territory, which covers all of San Diego County and an adjacent portion of Orange County.

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

(Dollars in millions)	Quarters ended March 31	June 30	September 30	December 31
2007				
Operating revenues	$ 709	$ 659	$ 716	$ 768
Operating expenses	589	548	549	666
Operating income	$ 120	$ 111	$ 167	$ 102
Net income	$ 63	$ 52	$ 125	$ 48
Dividends on preferred stock	1	1	2	1
Earnings applicable to common shares	$ 62	$ 51	$ 123	$ 47
2006				
Operating revenues	$ 722	$ 664	$ 703	$ 696
Operating expenses	623	539	555	591
Operating income	$ 99	$ 125	$ 148	$ 105
Net income	$ 48	$ 66	$ 72	$ 56
Dividends on preferred stock	1	1	2	1
Earnings applicable to common shares	$ 47	$ 65	$ 70	$ 55

Net income in the third quarter of 2007 included favorable resolutions of prior years' income tax issues of $20 million and regulatory matters of $26 million.

Net income for the second quarter of 2006 included $8 million from the CPUC authorization for retroactive recovery on SONGS revenues related to a computational error in the 2004 Cost of Service and $4 million as a result of FERC approval to recover prior year ISO charges in 2006. Net income in the third quarter of 2006 included $13 million resolution of a prior year cost recovery issue. Net income for each of the last three quarters of 2006 included increased earnings from electric generation activities primarily from the commencement of commercial operation of the Palomar generating plant at the beginning of the second quarter. Increased earnings from electric generation were $15 million in the second quarter, $12 million in the third quarter and $14 million in the fourth quarter.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f). The company has designed and maintains disclosure controls and procedures to ensure that information required to be disclosed in the company's reports is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and is accumulated and communicated to the company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. 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. In addition, the company consolidates a variable interest entity as defined in Financial Accounting Standards Board Interpretation (FIN) No. 46(R) that it does not control or manage and consequently, its disclosure controls and procedures with respect to this entity are necessarily limited to oversight or monitoring controls that the company has implemented to provide reasonable assurance that the objectives of the company's disclosure controls and procedures as described above are met.

There have been no changes in the company's internal control over financial reporting during the company's most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

The company evaluates 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. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, the company evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures as of December 31, 2007, the end of the period covered by this report. Based on that evaluation, the company's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures were effective at the reasonable assurance level.

Management's Report on Internal Control Over Financial Reporting is included in Item 8 herein.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 is incorporated by reference from the Information Statement prepared for the June 2008 annual meeting of shareholders. The information required on the companies' executive officers is set forth below.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age*	Position*
Debra L. Reed	51	Chairperson, President and Chief Executive Officer
Michael R. Niggli	58	Chief Operating Officer
Dennis V. Arriola	47	Senior Vice President and Chief Financial Officer
James P. Avery	51	Senior Vice President - Electric
Lee Schavrien	53	Senior Vice President - Regulatory Affairs
Anne S. Smith	54	Senior Vice President - Customer Services
W. Davis Smith	58	Senior Vice President and General Counsel
Lee M. Stewart	62	Senior Vice President - Gas Operations
Robert M. Schlax	52	Vice President, Controller and Chief Accounting Officer

* As of February 26, 2008.

Each executive officer has been an officer or employee of Sempra Energy or one of its subsidiaries for more than five years, with the exception of Mr. Schlax. Prior to joining the company in 2005, Mr. Schlax was Chief Financial Officer, Treasurer and Vice President of Finance of Mercury Air Group, Inc. since 2002. Except for Mr. Avery, each executive officer of San Diego Gas & Electric Company holds the same position at Southern California Gas Company.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference from the Information Statement prepared for the June 2008 annual meeting of shareholders.

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

Security Ownership of Certain Beneficial Owners

The security ownership information required by Item 12 is incorporated by reference from the Information Statement prepared for the June 2008 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 is incorporated by reference from the Information Statement prepared for the June 2008 annual meeting of shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information regarding principal accountant fees and services as required by Item 14 is incorporated by reference from the Information Statement prepared for the June 2008 annual meeting of shareholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. Financial statements

	Page in This Report
Management's Responsibility for Financial Statements	36
Management's Report On Internal Control Over Financial Reporting	36
Reports of Independent Registered Public Accounting Firm	37
Statements of Consolidated Income for the years ended December 31, 2007, 2006 and 2005	40
Consolidated Balance Sheets at December 31, 2007 and 2006	41
Statements of Consolidated Cash Flows for the years ended December 31, 2007, 2006 and 2005	43
Statements of Consolidated Comprehensive Income and Changes in Shareholders' Equity for the years ended December 31, 2007, 2006 and 2005	45
Notes to Consolidated Financial Statements	46

2. Financial statement schedules

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

3. Exhibits

See Exhibit Index on page 91 of this report.

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 Statements No. 33-45599, 33-52834, 333-52150, 33-49837, and 333-133541 on Form S-3 of our reports dated February 25, 2008, relating to the financial statements of San Diego Gas & Electric Company ("the Company") (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company's adoption of Financial Accounting Standards Board ("FASB") Statement No. 157, *Fair Value Measurements*, effective January 1, 2007, FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*, effective January 1, 2007, and FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* effective December 31, 2006) and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of San Diego Gas & Electric Company for the year ended December 31, 2007.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 25, 2008

SIGNATURES

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

SAN DIEGO GAS & ELECTRIC COMPANY,
(Registrant)

By: /s/ Debra L. Reed
Debra L. Reed
Chairperson, President 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.

Name/Title	Signature	Date
Principal Executive Officer: Debra L. Reed Chairperson, President and Chief Executive Officer	/s/ Debra L. Reed	February 26, 2008
Principal Financial Officer: Dennis V. Arriola Senior Vice President and Chief Financial Officer	/s/ Dennis V. Arriola	February 26, 2008
Principal Accounting Officer: Robert M. Schlax Vice President, Controller and Chief Accounting Officer	/s/ Robert M. Schlax	February 26, 2008
Directors:		
Debra L. Reed, Chairperson	/s/ Debra L. Reed	February 26, 2008
Michael R. Niggli, Director	/s/ Michael R. Niggli	February 26, 2008
Mark A. Snell, Director	/s/ Mark A. Snell	February 26, 2008

EXHIBIT INDEX

The Registration Statements and 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) and/or Commission File Number 1-14201 (Sempra Energy).

Exhibit 3 -- Bylaws and Articles of Incorporation

Bylaws

3.01 Amended Bylaws of San Diego Gas & Electric effective August 4, 2003.

3.02 Amended and Restated Bylaws of San Diego Gas & Electric effective May 14, 2002.

Articles of Incorporation

3.03 Amended and Restated Articles of Incorporation of San Diego Gas & Electric Company effective November 10, 2006 (2006 SDG&E Form 10-K, Exhibit 3.02).

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 Description of preferences of Cumulative Preferred Stock, Preference Stock (Cumulative) and Series Preference Stock (incorporated by reference from SDG&E Amended and Restated Articles of Incorporation as of November 10, 2006, Exhibit 3.02 above).

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

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

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

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

Exhibit 10 -- Material Contracts

10.01 Form of Continental Forge and California Class Action Price Reporting Settlement Agreement dated as of January 4, 2006 (Form 8-K filed on January 5, 2006, Exhibit 99.1).

10.02 Form of Nevada Antitrust Settlement Agreement dated as of January 4, 2006 (Form 8-K filed on January 5, 2006, Exhibit 99.2).

10.03 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).

10.04 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).

Compensation

10.05 Form of Sempra Energy 1998 Long Term Incentive Plan, 2008 Performance-Based Restricted Stock Unit Award (2007 Sempra Energy Form 10-K, Exhibit 10.09).

10.06 Form of Sempra Energy 1998 Long Term Incentive Plan, 2008 Non-Qualified Stock Option Agreement (2007 Sempra Energy Form 10-K, Exhibit 10.10).

10.07 Sempra Energy Excess Cash Balance Plan dated December 5, 2005 (2006 Sempra Energy Form 10-K, Exhibit 10.08).

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

10.09 Sempra Energy 2005 Deferred Compensation Plan (San Diego Gas & Electric Form 8-K filed on December 7, 2004, Exhibit 10.1).

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

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

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

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

10.14 2003 Sempra Energy Executive Incentive Plan (2003 Sempra Energy Form 10-K, Exhibit 10.10).

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

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

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

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

Nuclear

10.19 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).

10.20 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.19 above)(1994 SDG&E Form 10-K, Exhibit 10.56).

10.21 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 10.19 above)(1994 SDG&E Form 10-K, Exhibit 10.57).

10.22 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 10.19 above)(SDG&E 1996 Form 10-K, Exhibit 10.59).

10.23 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 10.19 above)(SDG&E 1996 Form 10-K, Exhibit 10.60).

10.24 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 10.19 above)(SDG&E 1999 Form 10-K, Exhibit 10.26).

10.25 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 10.19 above)(SDG&E 1999 Form 10-K, Exhibit 10.27).

10.26 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 10.19 above)(2003 Sempra Energy Form 10-K, Exhibit 10.42).

10.27 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).

10.28 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 10.27 above)(SDG&E 1996 Form 10-K, Exhibit 10.62).

10.29 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 10.27 above)(SDG&E 1996 Form 10-K, Exhibit 10.63).

10.30 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 10.27 above)(SDG&E 1999 Form 10-K, Exhibit 10.31).

10.31 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 10.27 above)(SDG&E 1999 Form 10-K, Exhibit 10.32).

10.32 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 10.27 above)(2003 Sempra Energy Form 10-K, Exhibit 10.48).

10.33 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).

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

Exhibit 12 -- Statement Re: Computation Of Ratios

12.01 Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends for the years ended December 31, 2007, 2006, 2005, 2004 and 2003.

Exhibit 14 - Code of Ethics

14.01 Sempra Energy Code of Business Conduct and Ethics for Board of Directors and Senior Officers (also applies to directors and officers of San Diego Gas & Electric Company) (2006 Form 10-K, Exhibit 14.01).

Exhibit 23 – Consent of Independent Registered Public Accounting Firm, page 89.

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

AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
ARB	Accounting Research Bulletin
BCAP	Biennial Cost Allocation Proceedings
Bcf	Billion Cubic Feet (of natural gas)
Cal Fire	California Department of Forestry and Fire Protection
CARB	California Air Resources Board
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CPUC	California Public Utilities Commission
CRRs	Congestion Revenue Rights
DOE	Department of Energy
DRA	Division of Ratepayer Advocates
DSM	Demand-Side Management
DWR	Department of Water Resources
Edison	Southern California Edison Company
EIR	Environmental Impact Report
EIS	Environmental Impact Study
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gas

GRC	General Rate Case
IOUs	Investor-Owned Utilities
IRS	Internal Revenue Service
ISFSI	Independent Spent Fuel Storage Installation
ISO	Independent System Operator
LIFO	Last-in first-out inventory costing method
LTPP	Long-Term Procurement Plan
LNG	Liquefied Natural Gas
MMBtu	Million British Thermal Units (of natural gas)
MSCI	Morgan Stanley Capital International
MW	Megawatt
Ninth Circuit Court of Appeals	U.S. Court of Appeals for the Ninth Circuit
NRC	Nuclear Regulatory Commission
OIR	Order Instituting Rulemaking
OMEC	Otay Mesa Energy Center
OMEC LLC	Otay Mesa Energy Center, LLC
PBR	Performance-Based Regulation
PGE	Portland General Electric
PRP	Potentially Responsible Party
PX	Power Exchange
QFs	Qualifying Facilities
ROE	Return on Equity
RPS	Renewable Portfolio Standards
SDG&E	San Diego Gas & Electric Company
Sempra Utilities	Southern California Gas Company and San Diego Gas & Electric Company

SFAS	Statement of Financial Accounting Standards
SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
TURN	The Utility Reform Network
VaR	Value at Risk
VIE	Variable Interest Entity