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, 2003

OR

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

SEMPRA ENERGY

(Exact name of registrant as specified in its charter)

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

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

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

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

Title of each class	Name of each exchange on which registered
Common stock, without par value	New York and Pacific
Mandatorily redeemable trust preferred securities	New York
Equity units, due 2007	New York

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

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

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

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

Exhibit Index on page 44. Glossary on page 52.

Aggregate market value of the voting stock held by non-affiliates of the registrant as of January 31, 2004 was $7.1 billion.

Registrant's common stock outstanding as of January 31, 2004 was 227,231,411 shares.

DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the 2003 Annual Financial Report to Shareholders are incorporated by reference into Parts I, II, and IV.

Portions of the Proxy Statement prepared for the May 2004 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, national and international economic, competitive, political, legislative and regulatory conditions and developments; actions by the California Public Utilities Commission (CPUC), the California Legislature, the California Department of Water Resources (DWR), environmental and other regulatory bodies in countries other than the United States, and the Federal Energy Regulatory Commission (FERC); capital market conditions, inflation rates, interest rates and exchange rates; energy and trading markets, including the timing and extent of changes in commodity prices; weather conditions and conservation efforts; war and terrorist attacks; business, regulatory and legal decisions; the status of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company's business described in this report and other reports filed by the company from time to time with the Securities and Exchange Commission.

PART I

ITEM 1. BUSINESS

Description of Business

A description of Sempra Energy and its subsidiaries (the company) is given in "Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2003 Annual Report to Shareholders, which is incorporated by reference. The company has four separately managed reportable segments comprised of Southern California Gas Company (SoCalGas), San Diego Gas & Electric (SDG&E), Sempra Energy Trading (SET) and Sempra Energy Resources (SER). SoCalGas and SDG&E are collectively referred to as "the California Utilities."

Company Website

The company's website address is http://www.sempra.com/investor.htm. The company makes available free of charge through 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. The charters of the company's board of directors' (the board) audit, compensation and corporate governance committees, the board's corporate governance guidelines and the code of business conduct and ethics for directors and officers are posted on the company's website. Printed copies may be obtained by writing to the company's Corporate Secretary at Sempra Energy, 101 Ash Street, San Diego, CA 92101-3017.

RISK FACTORS

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

Risks Related to the California Utilities

The California Utilities are subject to extensive regulation by state, federal and local legislation and regulatory authorities, which may adversely affect the operations, performance and growth of their businesses.

The CPUC, which consists of five commissioners appointed by the Governor of California for staggered six-year terms, regulates the California

Utilities' rates and conditions of service, sales of securities, rates of return, rates of depreciation, uniform systems of accounts, examination of records and long-term resource procurement. The CPUC conducts various reviews of utility performance (including reasonableness and prudency reviews) and conducts audits and investigations into various matters which may, from time to time, result in disallowances and penalties adversely affecting earnings and cash flows. The CPUC also regulates the relationship of utilities with their affiliates and is currently conducting an investigation into this relationship. Various proceedings involving the CPUC and relating to the California Utilities' rates, costs, incentive mechanisms, performance-based regulation and affiliate and holding company rule compliance are discussed in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" incorporated by reference in this report.

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

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC adopted Performance-Based Regulation (PBR) for SDG&E effective in 1994 and for SoCalGas effective in 1997. Under PBR, regulators require future income potential to be tied to achieving or exceeding specific performance and productivity goals, rather than relying solely on expanding utility plant to increase earnings. The three areas that are eligible for PBR rewards are: operational incentives based on measurements of safety, reliability and customer satisfaction; demand-side management (DSM) rewards based on the effectiveness of the programs; and natural gas procurement rewards. Although the California Utilities have received significant PBR rewards in the past, there can be no assurance that the California Utilities will receive rewards at similar levels in the future, or at all. Additionally, if the California Utilities fail to achieve certain minimum performance levels established under the PBR mechanisms, they may be assessed financial disallowances or penalties which could adversely affect their earnings and cash flows.

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

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

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

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

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

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

Lawsuits filed in 2000 and currently consolidated in San Diego Superior Court seek class-action certification and damages, alleging Sempra Energy and the California Utilities, along with El Paso Energy Corp. and several of its affiliates, unlawfully sought to control natural gas markets. Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada and by others. Although the California Utilities expect to prevail in these cases, they have expended or accrued substantial amounts to pay the costs of defending these claims. If the plaintiffs in these cases were to prevail in their claims, the future results of operations and financial condition of Sempra Energy and the California Utilities may be materially adversely affected. In addition, various other lawsuits are pending against SDG&E and other Sempra Energy subsidiaries alleging that the companies unlawfully manipulated the electric energy market.

In December 2002, the CPUC approved a settlement with SDG&E allocating between SDG&E's customers and shareholders the profits from certain intermediate-term power purchase contracts that SDG&E had entered into during the early stages of California's electric utility industry restructuring. As a result of the CPUC's decision, SDG&E recognized additional after-tax income of $65 million in 2003. The Utility Consumers' Action Network (UCAN) has appealed the decision and the California Court of Appeals granted the petition for review.

These proceedings are discussed in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" incorporated by reference in this report.

Risks Related to Sempra Energy's Electric Generation, Energy Trading, Liquefied Natural Gas (LNG), Energy Solutions, International and Other Businesses

Sempra Energy's businesses are exposed to market risk, and its financial condition, results of operations, cash flows and liquidity may be adversely affected by fluctuations in commodity market prices that are beyond its control.

Sempra Energy Trading (SET) is a full-service trading company that markets and trades physical and financial commodity products. Its trading portfolios consist of physical and financial commodity contracts including contracts for natural gas, electricity, petroleum products, base metals and other commodities that are settled by the delivery of the commodity or cash. Although SET generally seeks to structure its trading contracts so that a substantial majority of its trading revenues are realizable within 24 months and strives to maintain proper hedging mechanisms for its trading book, at times SET may have unhedged trading positions in the market, resulting from the management of its trading portfolios or from its inability to hedge, in whole or in part, particular risks.

Sempra Energy Resources (SER) generates and sells electricity on a long-term basis, or into the spot market or other competitive markets, and purchases natural gas for its power plants and sometimes purchases electricity in the open market to satisfy its contractual obligations.

Sempra Energy Solutions (SES) procures electricity and natural gas for its commercial and industrial customers. The market prices for these commodities may fluctuate substantially over relatively short periods of time.

Sempra Energy's sales and results of operations could be adversely affected if the prevailing market prices for electricity, natural gas or other commodities that are procured for power plants or to satisfy contractual obligations (whether to trading counterparties or otherwise), or that are provided to customers in regional markets and other competitive markets in which the company competes, change in a direction or manner that it does not anticipate.

Unanticipated changes in market prices for energy-related and other commodities result from multiple factors, including: weather conditions; seasonality; changes in demand; transmission or transportation constraints or inefficiencies; availability of competitively priced alternative energy sources; commodity production levels; actions by OPEC (Organization of the Petroleum Exporting Countries) with respect to the supply of crude oil; federal, state and foreign energy and environmental regulation and legislation; natural disasters, wars, embargoes and other catastrophic events; and expropriation of assets by foreign countries.

In 2001 the FERC, which has jurisdiction over wholesale power and transmission rates and independent system operators and other entities that control transmission facilities or that administer wholesale power sales in some of the markets in which the company operates, imposed price limitations which resulted in unexpected moves in electricity prices. The FERC may impose additional price limitations, bidding rules and other mechanisms or terminate existing price limitations from time to time in the future. Any such action by the FERC may result in prices for electricity changing in an unanticipated direction or manner, and may have an adverse effect on Sempra Energy's sales and results of operations.

Sempra Energy and its subsidiaries cannot and do not attempt to fully hedge their assets or positions against changes in commodity prices, and their hedging procedures may not work as planned.

To lower financial exposure related to commodity price fluctuations, Sempra Energy's subsidiaries routinely enter into contracts to hedge a substantial portion of their purchase and sale commitments and inventories of electricity, natural gas, crude oil, refined petroleum products and other commodities. As part of this strategy, they routinely utilize fixed-price, forward, physical purchase and sales contracts, futures, financial swaps and option contracts traded in the over-the-counter markets or on exchanges. However, the company does not always cover the entire exposure of its assets or its positions to market price volatility and the coverage will vary over time. To the extent Sempra Energy or its subsidiaries have unhedged positions, or if their hedging positions do not work as planned, fluctuating commodity prices could have a material adverse effect on Sempra Energy's business, results of operations, cash flows and financial condition.

Risk management procedures may not prevent losses.

Although Sempra Energy and its subsidiaries have risk management systems and control systems in place that use advanced methodologies to quantify risk, these systems may not prevent material losses. The risk management procedures the company has in place may not always be followed or may not always work as planned. In addition, daily value-at-risk and loss limits are derived from historic price movements. If prices significantly deviate from historic prices, the limits may not protect the company from significant losses. As a result of these and other factors, there can be no assurances that Sempra Energy's risk management procedures will prevent losses that would negatively affect its business, results of operations, cash flows and financial condition.

A downgrade in Sempra Energy's credit ratings could negatively affect its energy trading and other non-utility businesses.

If Sempra Energy's credit ratings were to be downgraded, the business prospects of its energy trading and other non-utility businesses, which generally rely on the creditworthiness of Sempra Energy, would be adversely affected. SET would be required to comply with various margin or other credit enhancement obligations under many of the trading and marketing contracts into which it has entered, substantially all of which are guaranteed by Sempra Energy, and it may be able to continue to trade only on less favorable terms. To meet liquidity requirements, Sempra Energy and its subsidiaries maintain substantial unused committed lines of credit for which borrowings are available without regard to credit ratings. A ratings downgrade could require Sempra Energy to divert to SET all or a portion of the liquidity that these lines would otherwise provide for the expansion of Sempra Energy's other non-utility businesses. In addition, if these lines were to become unavailable or to be inadequate to meet SET's margin or other credit enhancement requirements, SET's trading partners could exercise other remedies such as liquidating and netting their exposures to SET, making it more difficult or impossible for SET to manage effectively its remaining trading positions or to continue its trading business, and Sempra Energy and its subsidiaries may not have sufficient liquidity to meet their obligations.

Sempra Energy's businesses depend on counterparties, customers and suppliers performing in accordance with their agreements, and any failure by them to perform could require the company to incur substantial expenses and expose it to commodity price risk and volatility, which could adversely affect Sempra Energy's liquidity, cash flows and results of operations.

Sempra Energy's subsidiaries are exposed to the risk that counterparties, customers and suppliers that owe money or energy as a result of market transactions or other long-term agreements will not perform their obligations under such agreements. Should they fail to perform, the company may be required to acquire alternative hedging arrangements or to honor the underlying commitment at then-current market prices. In such event, Sempra Energy's subsidiaries may incur additional losses to the extent of amounts already paid to such counterparties or suppliers. In addition, the subsidiaries often extend credit to counterparties and customers. While the company performs significant credit analyses prior to extending credit, Sempra Energy and its subsidiaries are exposed to the risk that they may not be able to collect amounts owed to them.

If the DWR were to succeed in setting aside, or were to fail to perform its obligations under its long-term power contract with SER, Sempra Energy's business, results of operations and cash flows will be materially adversely affected.

In 2001, SER entered into a 10-year power sales agreement with the DWR, to supply up to 1,900 megawatts to the state. Sempra expects the contract with the DWR will be a source of significant revenue over the 10-year period. The validity of the power sales agreement with the DWR has been the subject of extensive litigation between the parties before the FERC and in California courts. Although SER has prevailed in all of these challenges to date, the plaintiffs in these actions have appealed several of these rulings. Although SER expects to prevail in these appeals, if the DWR were to succeed in setting aside its obligations under the contract, or if the DWR fails or is unable to meet its contractual obligations on a timely basis, it could have a material adverse effect on Sempra Energy's business, results of operations, cash flows and financial condition. These proceedings are described in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" incorporated by reference in this report.

In the future, Sempra Energy and its subsidiaries may elect not to or may not be able to enter into long-term supply and sales agreements or long-term firm capacity agreements for their projects, which would subject Sempra Energy's sales to increased volatility and its businesses to increased competition.

The electric generation and wholesale power sales industries have become highly competitive. As more plants are built and competitive pressures increase, the wholesale pricing of electricity becomes more volatile. Without the benefit of long-term power sales agreements, such as the 10-year power sales agreement between SER and the DWR, Sempra Energy's sales will be subject to increased price volatility, and it may be unable to sell the power generated by SER's facilities or operate those facilities profitably.

Sempra Energy LNG Corp. (SELNG) does not intend to commence significant construction of its proposed LNG terminals without first entering into long-term LNG supply agreements and corresponding natural gas sales agreements, or long-term firm capacity service agreements, for a substantial portion of the processing capacity of these facilities. However, if these plans were to change and the company were to construct its terminals without the benefit of such long-term agreements, its sales would be subject to increased price volatility, and it may be unable to sell the services of its LNG facilities or to operate the facilities profitably. If the counterparties, customers or suppliers to one or more of the key agreements for the LNG facilities were to fail or become unable to meet their contractual obligations on a timely basis, it could have a significant negative impact on Sempra Energy's business, results of operations, cash flows and financial condition.

Business development activities may not be successful and projects under construction may not commence operation as scheduled, which could increase Sempra Energy's costs and impair its ability to recover its investments.

The acquisition, development and construction of electric generating facilities and LNG receiving terminals involve numerous risks. Sempra Energy and its subsidiaries may be required to expend significant sums for preliminary engineering, permitting, fuel supply, resource exploration, legal and other expenses in preparation for competitive bids which they may not win or before it can be established whether a project is feasible, economically attractive or capable of being built. Sempra Energy's success in developing a particular project is contingent upon, among other things, negotiation of satisfactory engineering, procurement and construction agreements, fuel supply and power sales contracts (for generating facilities), LNG supply and natural gas sales agreements or firm capacity service agreements (for LNG receiving terminals), receipt of required governmental permits and timely implementation and satisfactory completion of construction. Successful completion of a particular project may also be adversely affected by unforeseen engineering problems, construction delays and contractor performance shortfalls, work stoppages, adverse weather conditions, environmental and geological conditions, and other factors. If the company is unable to complete the development of a facility, it typically will not be able to recover its investment in the project.

Generation facilities and/or LNG terminals may not operate as planned, which may adversely affect Sempra Energy's business, cash flows and results of operations.

The operation of power plants and LNG receiving terminals involves many risks, including the breakdown or failure of generation or regasification and storage facilities or other equipment or processes, labor disputes, fuel interruption and operating performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, regasification and transmission delivery systems. The occurrence of any of these events could lead to operation of power plants or LNG terminals below their expected capacity levels, which may result in lost revenues or increased expenses, including higher maintenance costs and penalties, and could adversely affect Sempra Energy's business, cash flows and results of operations.

Competition among developers and operators of LNG terminals is rapidly increasing, which may adversely affect the profitability of SELNG's proposed LNG terminals.

Although there are only a limited number of LNG terminal facilities operating in North America today, many companies have announced plans to develop LNG facilities to serve the North American market. Some of these competitors have more operating experience, more development experience, larger staffs and greater financial resources than the company. Industry analysts have predicted that if all of the proposed LNG facilities in North America that have been announced by developers are actually built, there will likely be substantial excess capacity for such terminals in the near future. Excess capacity is likely to lead to decreased prices for such services. Although its proposed LNG facilities in Mexico and Louisiana are more advanced in the siting, permitting and regulatory approval processes than the proposed projects of most of its competitors, there can be no assurance that Sempra Energy will be able to maintain that advantage.

Sempra Energy's subsidiaries rely on transmission and distribution assets that they do not own or control to deliver electricity and natural gas.

Sempra Energy's subsidiaries depend on transmission and distribution facilities owned and operated by third parties to deliver the electricity and natural gas they sell to wholesale markets, to supply some of their electric generation facilities, and to provide retail energy services to customers. SELNG also will rely on natural gas transmission facilities to transport natural gas for customers of its proposed LNG terminal facilities. If transmission is disrupted, or if capacity is inadequate, the ability of Sempra Energy's subsidiaries to sell and deliver their products and services may be hindered. As a result, they may be responsible for damages incurred by their customers, such as the additional cost of acquiring alternative supply at then-current spot market rates.

Sempra Energy's businesses require numerous permits and other governmental approvals from various federal, state, local and foreign governmental agencies, and any failure to obtain or maintain required permits or approvals could cause Sempra Energy's sales to decline and/or its costs to increase.

The acquisition, ownership and operation of electric generation facilities, natural gas pipelines and LNG receiving terminals require numerous permits, approvals and certificates from federal, state, local and foreign governmental agencies. All of the existing and planned development projects of Sempra Energy's subsidiaries require multiple permits. They may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approvals or if the company fails to obtain any required approvals or to comply with any applicable laws or regulations, it may not be able to operate its facilities, or it may be forced to incur additional costs.

Sempra Energy's future results of operations, cash flows and financial condition may be adversely affected by the outcomes of pending litigation and other adversarial proceedings involving Sempra Energy and some of its subsidiaries, including SET and SER.

Lawsuits have been filed by the Attorneys General of Arizona and Nevada, alleging that Sempra Energy and some of its subsidiaries, along with El Paso Energy and several of its affiliates, unlawfully sought to control the natural gas markets in their respective states. Similar lawsuits have been filed elsewhere. In addition, various lawsuits are pending against Sempra Energy, SET, SER and other Sempra Energy subsidiaries, alleging that the companies unlawfully manipulated the electric energy market. Although the company expects to prevail in these cases, it has expended or accrued substantial amounts to pay the costs of defending these claims. If the plaintiffs in these cases were to prevail in their claims, Sempra Energy's future results of operations, cash flows and financial condition may be materially adversely affected. These proceedings are discussed in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" incorporated by reference in this report.

Sempra Energy's energy and energy trading businesses are subject to complex government regulations and may be adversely affected by changes in these regulations or in their interpretation or implementation.

In recent years, the regulatory environment applicable to the electric power and natural gas industries has undergone significant changes, both on a federal and state level, which have impacted the nature of these industries and the manner in which their participants conduct their businesses. These changes are ongoing, and Sempra Energy cannot predict the future course of changes in this regulatory environment or the ultimate affect that this changing regulatory environment will have on its businesses. Moreover, existing regulations may be revised or reinterpreted, and new laws and regulations may be adopted or become applicable to the company and its facilities. Future changes in laws and regulations may have a detrimental effect on Sempra Energy's business, cash flows, financial condition and/or results of operations.

Sempra Energy's energy and energy trading operations are subject to affiliate rules relating to transactions with the California Utilities. These businesses could be adversely affected by changes in these rules or by additional CPUC or FERC rules' further restricting their ability to sell electricity or gas or to trade with the California Utilities. Affiliate transaction rules also could require these businesses to obtain the prior approval of the CPUC before entering into any such transactions with the California Utilities. Any such restrictions or approval requirements could adversely affect SER's and SEI's electric generation plants or natural gas pipelines, SELNG's proposed LNG receiving terminals, or SET trading operations.

Various proceedings, inquiries and investigations relating to the business activities of SER and SET are currently pending before the FERC. For a description of such proceedings, inquiries and investigations, see the notes to Consolidated Financial Statements and "Management's Discussion and Analysis of Financial Condition and Results of Operations" incorporated by reference in this report.

Sempra Energy's businesses have significant environmental compliance costs, and future environmental compliance costs could adversely affect Sempra Energy's profitability.

Sempra Energy's subsidiaries are subject to extensive federal, state, local and foreign statutes, rules and regulations relating to environmental protection. They are required to obtain numerous governmental permits, licenses and other approvals to construct and operate their businesses. Additionally, to comply with these legal requirements, they must spend significant sums on environmental monitoring, pollution control equipment and emissions fees. 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 which it has acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. If Sempra Energy's subsidiaries fail to comply with applicable environmental laws, they may be subject to penalties, fines and/or curtailments of their operations.

The scope and extent of any new environmental regulations, including their affects on operations, are difficult to predict. In addition, existing environmental regulations could be revised or reinterpreted and new laws and regulations could be adopted or become applicable to the company and its facilities.

Sempra Energy's international businesses are exposed to different local, regulatory and business risks and challenges, which could have a material adverse effect on Sempra Energy's financial condition, cash flows and results of operations.

Sempra Energy subsidiaries currently have interests in electricity generation, natural gas transmission and LNG terminal projects in Mexico, and also have trading, marketing and risk management operations in Canada, Europe and Asia. Sempra Energy International (SEI) also has electricity and natural gas distribution businesses in Argentina, Chile and Peru. Having energy infrastructure projects, owning energy assets and operating businesses in foreign jurisdictions subject the company to significant political and financial risks which vary by country, including:

- -- changes in foreign laws and regulations, including tax and environmental laws and regulations;
- -- changes in U.S. laws and regulations, including tax and environmental laws and regulations, related to foreign operations;
- -- high rates of inflation;
- -- changes in government policies or personnel;
- -- trade restrictions;

- -- limitations on U.S. company ownership in foreign countries;
- -- permitting and regulatory compliance;
- -- changes in labor supply and labor relations in operations outside the United States;
- -- adverse rulings by foreign courts or tribunals and difficulty in enforcing contractual rights in foreign jurisdictions; and
- -- general political, economic and business conditions.

Sempra Energy's international businesses also are subject to foreign currency risks. These risks arise from both volatility in foreign currency exchange rates and devaluations of foreign currencies. In such cases, an appreciation of the U.S. dollar against a local currency could reduce the amount of cash and income received from those foreign subsidiaries. For example, the devaluation of the Argentine peso against the U.S. dollar in recent years (as well as the Argentine government's unilateral, retroactive abrogation of utility agreements early in 2002) has had a material adverse effect on SEI's two unconsolidated subsidiaries in Argentina. On September 6, 2002, SEI initiated arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its investments that has resulted from Argentine governmental actions. SEI has claimed damages of at least $258 million these proceedings, which are continuing. For a description of legal proceedings relating to SEI's business operations in Argentina, see the notes to Consolidated Financial Statements incorporated by reference in this report. While SEI believes that it has contracts and other measures in place to mitigate its most significant foreign currency exchange risks, it has some exposure that is not fully mitigated.

Other Risks Related to the Company

Sempra Energy's cash flows, ability to pay dividends and ability to meet its debt obligations largely depend on the performance of its subsidiaries.

Sempra Energy is a holding company and conducts its operations entirely through its subsidiaries. Sempra Energy's California Utilities are its major source of liquidity. Funding of other business units' capital expenditures is largely dependent on the California Utilities' paying sufficient dividends to Sempra Energy, which depends on the sufficiency of utility earnings and cash flows in excess of utility needs. In addition, Sempra Energy's cash flows, ability to meet its obligations to creditors and its ability to pay dividends on its common stock are largely dependent upon the earnings of the subsidiaries and the distribution of such earnings to Sempra Energy in the form of dividends. The subsidiaries are separate and distinct legal entities and could be precluded from making such distributions under certain circumstances, including as a result of legislation or regulation or in times of financial distress.

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

Like other major industrial facilities, Sempra Energy's generation plants (including SONGS), electric transmission facilities, LNG receiving terminals and storage facilities, chartered oil tankers and natural gas pipelines 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 and/or significant additional costs to the company, which could have a material adverse effect on Sempra Energy's earnings and cash flows. Given the nature and location of these facilities, any such incidents also could cause fires, leaks, explosions, spills or other significant damage to natural resources and/or property belonging to third parties, or personal injuries, which could lead to significant claims against Sempra Energy and its subsidiaries. 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.

Sempra Energy could incur significant income tax expense and its results of operations and cash flows may be materially adversely affected if the Internal Revenues Service (IRS) denies or otherwise makes income tax credits related to its coal and synthetic fuels businesses unusable.

Sempra Energy generates substantial income tax credits as a result of synthetic fuel operations and affordable-housing investments. These credits substantially reduce the company's income tax expense.

In 2003, the IRS questioned the scientific validity of the testing procedures used to support synthetic fuel credits. The IRS has completed its review of these procedures and resumed issuing letter rulings based on its previous requirements, including one involving operations owned by Sempra Energy. However, as part of its recently commenced normal audit program for the company for the period 1998-2001, the IRS has begun auditing the company's synthetic fuel operations. In addition, a U.S. Senate subcommittee has initiated an investigation into income tax credits, and Sempra Energy and other companies are responding to subcommittee requests regarding their synthetic fuel operations. Through December 31, 2003, Sempra Energy has recorded cumulative synthetic fuel income tax credits of $256 million, including $106 million for the fiscal year ended December 31, 2003.

Although Sempra Energy believes the retroactive disallowance of its synthetic fuel credits is unlikely, any such retroactive disallowance could result in a significant liability for income tax credits previously taken. In addition, Sempra Energy's use of income tax credits in the future could be limited by any new IRS interpretations or regulations or by any new income tax legislation.

GOVERNMENT REGULATION

The most significant government regulation affecting Sempra Energy is that affecting its utility subsidiaries.

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 and SoCalGas' rates and conditions of service, sales of securities, rate of return, rates of depreciation, uniform systems of accounts, examination of records, and long-term resource procurement. The CPUC conducts various reviews of utility performance and conducts investigations into various matters, such as deregulation, competition and the environment, to determine its future policies. The CPUC also regulates the relationship of utilities with their holding companies and is currently conducting an investigation into this relationship.

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

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

United States Utility Regulation

The FERC regulates the interstate sale and transportation of natural gas, the transmission and wholesale sales of electricity in interstate commerce, transmission access, the uniform systems of accounts, rates of depreciation and electric rates involving sales for resale. Both the FERC and the CPUC are currently investigating prices charged to the California investor-owned utilities (IOUs) by various suppliers of natural gas and electricity. See further discussion in Notes 13 and 14 of the notes to Consolidated Financial Statements of the 2003 Annual Report to Shareholders, which is incorporated by reference.

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

Local Regulation

SoCalGas has natural gas franchises with the 240 legal jurisdictions in its service territory. These franchises allow SoCalGas to locate facilities for the transmission and distribution of natural gas in the streets and other public places. Some franchises have fixed terms, such as that for the city of Los Angeles, which expires in 2012. Most of the franchises do not have fixed terms and continue indefinitely. The range of expiration dates for the franchises with definite terms is 2005 to 2048.

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 facilities for the transmission and distribution of electricity and/or natural gas in the streets and other public places. The franchises do not have fixed terms, except for the electric and natural gas franchises with the cities of Encinitas (2012), San Diego (2021) and Coronado (2028), and the natural gas franchises with the city of Escondido (2036) and the county of San Diego (2030). The franchise agreement with the city of Chula Vista expired during 2003 but continues on a month-to-month basis while a new agreement is being negotiated.

SEI's Mexican subsidiaries Distribuidora de Gas Natural (DGN) de Mexicali, DGN de Chihuahua and DGN de La Laguna Durango build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. These companies are regulated by city and state government labor and environmental agencies.

Other Regulation

The company's unconsolidated utility affiliates have operations in Argentina, Chile and Peru. These operations are subject to the local, federal and other regulations of the countries and/or political subdivisions in which they are located.

SET has trading locations in North America, Europe and Asia that are subject to regulation as to operations and financial position. Among other things, its operations are subject to the New York Mercantile Exchange, the London Metals Exchange, the Commodity Futures Trading Commission, the FERC and the National Futures Association.

Other subsidiaries are also subject to varying amounts of regulation by various governments, including various states in the United States.

Licenses and Permits

The California Utilities obtain a number of permits, authorizations and licenses in connection with the transmission and distribution of natural gas. In addition, SDG&E obtains a number of permits, authorizations and licenses in connection with the transmission and distribution of electricity. Both require periodic renewal, which results in continuing regulation by the granting agency.

The company's unregulated affiliates are also required to obtain permits, authorizations and licenses in the normal course of business. Some of these permits, authorizations and licenses require periodic renewal. SER and its subsidiaries obtain a number of permits, authorizations and licenses in connection with the construction and operation of power generation facilities. In addition, SER obtains permits in connection with wholesale distribution of electricity. SES obtains permits in connection with the construction and operation of various facilities and with the retail sale of electricity and natural gas. SEI's Mexican subsidiaries obtain construction permits for their distribution systems from the local governments where the service is provided. SELNG obtains licenses and permits for LNG construction and operations.

Other regulatory matters are described in Notes 13 and 14 of the notes to Consolidated Financial Statements of the 2003 Annual Report to Shareholders, which is incorporated by reference.

SOURCES OF REVENUE

Industry segment information is contained in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 16 of the notes to Consolidated Financial Statements of the 2003 Annual Report to Shareholders, which is incorporated by reference. Various information concerning revenue and revenue recognition is provided in Note 1 of the notes to Consolidated Financial Statements of the 2003 Annual Report to Shareholders.

NATURAL GAS OPERATIONS

Resource Planning and Natural Gas Procurement and Transportation

The company is engaged in the sale, distribution, storage and transportation of natural gas through the California Utilities. 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 14 and 15 of the notes to Consolidated Financial Statements of the 2003 Annual Report to Shareholders, which is incorporated by reference.

Customers

For regulatory purposes, customers are separated into core and noncore customers. Core customers are primarily residential and small commercial and industrial customers without alternative fuel capability. Noncore customers consist primarily of electric generation (EG), wholesale, large commercial, industrial and enhanced oil recovery customers.

Most core customers purchase natural gas directly from the California Utilities. Core customers are permitted to aggregate their natural gas requirement and purchase directly from brokers or producers. The California Utilities continue to be obligated to purchase reliable supplies of natural gas to serve the requirements of the core customers.

Natural Gas Procurement and Transportation

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

To ensure the delivery of the natural gas supplies to the distribution system and to meet the seasonal and annual needs of customers, SoCalGas is committed to firm pipeline capacity contracts that require the payment of fixed reservation charges to reserve firm transportation entitlements. SoCalGas releases and brokers excess capacity on a short-term basis. Interstate pipeline companies, primarily El Paso Natural Gas Company and Transwestern Pipeline Company, provide transportation services into SoCalGas' intrastate transmission system for supplies purchased by SoCalGas or its transportation customers from outside of California. The last of these contracts expires in 2007. The rates that interstate pipeline companies may charge for natural gas and transportation services are regulated by the FERC.

SDG&E also has long-term natural gas transportation contracts with various interstate pipelines which expire on various dates through 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues to evaluate its long-term pipeline capacity portfolio, including the release of a portion of this capacity to third parties. All of SDG&E's natural gas is delivered through SoCalGas pipelines under a short-term transportation agreement authorized by the CPUC. In addition, under a separate agreement expiring March 2005, SoCalGas provides SDG&E 8 bcf of storage inventory capacity with firm injection and withdrawal rights.

According to "Btu's Daily Gas Wire," the annual average spot price of natural gas at the California/Arizona border was $5.10 per million British thermal unit (mmbtu) in 2003 ($5.59 in December 2003), compared with $3.14 per mmbtu in 2002 and $7.27 per mmbtu in 2001. A number of factors associated with California's energy crisis from late 2000 through early 2001 resulted in higher natural gas prices during that period. Prices for natural gas decreased in the later part of 2001 and increased toward the end of 2002 and in 2003. The following table summarizes the average commodity costs of natural gas sold for the last three years, which are above previous levels:

Years ended December 31,	2003	2002	2001
Cost of natural gas	$2,071	$1,381	$2,549
Volumes delivered (bcf)	394	406	410
Average cost of natural gas (dollars per bcf)	$ 5.26	$ 3.40	$ 6.22

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

Natural Gas Storage

SoCalGas provides natural gas storage services for use by the core, noncore and off-system customers. Core customers are allocated a portion of SoCalGas storage capacity. Remaining customers can bid and negotiate the desired amount of storage on a contract basis. The storage service program provides opportunities for customers to store natural gas, usually during the summer, to reduce winter purchases when natural gas costs are generally higher. This allows customers to select the level of service they desire to assist them to manage their fuel procurement and transportation needs.

Demand for Natural Gas

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

Effective March 31, 1998, electric industry restructuring provided out-of-state producers the option to purchase energy for California utility customers. As a result, natural gas demand for electric generation within Southern California competes with electric power generated throughout the western United States. Although electric industry restructuring has no direct impact on the California Utilities' natural gas operations, future volumes of natural gas transported for electric generating plant customers may be significantly affected to the extent that regulatory changes divert electric generation from the California Utilities' service area.

Growth in the natural gas markets is largely dependent upon the health and expansion of the Southern California economy and prices of other energy products. External factors such as weather, the price of electricity, electric deregulation, the use of hydroelectric power, competing pipelines and general economic conditions can result in significant shifts in demand and market price. The California Utilities added 83,000 and 75,000 new customer meters in 2003 and 2002, respectively, representing growth rates of 1.4 percent and 1.2 percent respectively. The California Utilities expect that their growth rate for 2004 will approximate that for 2003.

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

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

ELECTRIC OPERATIONS

Customers

At December 31, 2003 the company had 1.3 million meters consisting of 1,150,000 residential, 136,000 commercial, 450 industrial, 1,800 street and highway lighting, 8,000 direct access and 24 off-system. The company's service area covers 4,100 square miles. The company added 18,000 new customer meters in 2003 and 20,000 in 2002, representing growth rates of 1.4% and 1.6% respectively.

Resource Planning and Power Procurement

SDG&E's resource planning, power procurement and related regulatory matters are discussed below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 13 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

Electric Resources

Based on CPUC-approved purchased-power contracts currently in place with SDG&E's various suppliers and SDG&E's 20-percent share of a generating plant, as of December 31, 2003, the supply of electric power available to SDG&E is as follows:

Supplier	Source	Expiration date	Megawatts
Generation: SONGS			430
Purchased power contracts:			
Long-term contracts:			
Portland General Electric (PGE)	Coal	December 2013	84
DWR-allocated contracts:			
Williams Energy Marketing & Trading	Natural gas	December 2010	1,875
Sunrise Power Co. LLC	Natural gas	June 2012	572
Other	Natural gas/wind	2004 to 2013	328
Total			2,775
Other contracts with Qualifying Facilities (QFs):			
Applied Energy Inc.	Cogeneration	November 2019	107
Yuma Cogeneration	Cogeneration	May 2024	57
Goal Line Limited Partnership	Cogeneration	February 2025	50
Other (73 contracts)	Cogeneration	Various	16
Total			230
Other contracts with renewable sources:			
Various (9 contracts)	Bio-gas	5-15 year terms starting in 2003	28
Various (1 contract)	Bio-mass	5 year term starting in 2003	49
Various (5 contracts)	Wind	10-15 year terms starting in 2003	159
Total sources			236
Total generation and contracted			3,755

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 costs. Costs under the contracts with QFs are based on SDG&E's avoided cost. Charges under the remaining contracts are for firm and as-available energy and are based on the amount of energy received. The prices under these contracts are at the market value at the time the contracts were negotiated.

SONGS:

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

Unit 1 was removed from service in November 1992 when the CPUC issued a decision to permanently shut it down. Storage and decommissioning of Unit 1's spent nuclear fuel is now in progress.

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

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

Additional information concerning the SONGS units, nuclear decommissioning and industry restructuring is provided below and in "Environmental Matters" herein, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 6, 13, 14 and 15 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

Nuclear Fuel Supply

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

Spent fuel from SONGS is being stored on site, where storage capacity is expected to be adequate at least through 2022, the expiration date of the NRC operating license. Pursuant to the Nuclear Waste Policy Act of 1982, SDG&E entered into a contract with the U.S. Department of Energy (DOE) for spent-fuel disposal. Under the agreement, the DOE is responsible for the ultimate disposal of spent fuel. SDG&E pays a disposal fee of $1.00 per megawatt-hour of net nuclear generation, or $3 million per year. The DOE projects that it will not begin accepting spent fuel until 2010 at the earliest.

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

Additional information concerning nuclear-fuel costs is provided in Note 15 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

Power Pools

SDG&E is a participant in the Western Systems Power Pool, which includes an electric-power and transmission-rate agreement with utilities and power agencies located throughout the United States and Canada. More than 280 investor-owned and municipal utilities, state and federal power agencies, energy brokers, and power marketers share power and information in order to increase efficiency and competition in the bulk power market. Participants are able to make power transactions on standardized terms that have been pre-approved by FERC.

Transmission Arrangements

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

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

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

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

Transmission Access

The FERC has established rules to implement the transmission-access provisions of the National Energy Policy Act of 1992. These rules specify procedures for others' requests for transmission service. In October 1997, the FERC approved the California IOUs' transfer of control of their transmission facilities to the ISO. In 1998, operation and control of the transmission lines was transferred to the ISO. Additional information regarding the ISO and transmission access is provided below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2003 Annual Report to Shareholders, which is incorporated by reference.

SEMPRA ENERGY GLOBAL ENTERPRISES

Sempra Energy Global Enterprises (Global) consists of most of the businesses of Sempra Energy other than the California Utilities, and serves a broad range of customers' energy needs. Global includes SET, SER, SEI, SES, SELNG and several smaller business units. See below for a discussion of each of these business units.

Additional information concerning these and other aspects of the operations of Global Enterprises and Sempra Energy Financial (SEF) is provided under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 3 and 15 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

SEMPRA ENERGY TRADING

SET is a full-service trading company that markets and trades physical and financial commodity products, including natural gas, power, petroleum products and base metals. SET combines trading, risk-management and physical commodity expertise to provide innovative solutions to its customers worldwide.

SEMPRA ENERGY RESOURCES

SER is an energy company engaged in the development, construction, ownership and operation of power generation facilities and the sale of electricity, primarily in the western United States.

In May 2001, SER entered into a ten-year agreement with the DWR to supply up to 1,900 MW of electricity to the state. SER may deliver most of this electricity from its plants in the western United States and Baja California, Mexico. Sales under the contract comprise more than two-thirds of the projected capacity of these facilities and the profits therefrom are significant to the company's ability to increase its earnings.

The company believes that SER's contract prices are just and reasonable, but has offered to renegotiate certain aspects of the contract (which would not affect the long-term profitability) in a manner mutually beneficial to SER and the state. Although the contract is subject to ongoing litigation and regulatory proceedings, both SER and the State of California are performing under this contract. Information concerning the litigation is provided in Note 15 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

During 2003 construction was completed on the 1,250-megawatt Mesquite Power plant, with commercial operations commencing at 50% capacity in June 2003 and 100% capacity in December 2003. The project had been initially financed through a synthetic lease agreement. As a result of the implementation of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51," the company consolidated Mesquite Trust, the legal entity which owns Mesquite Power, in its consolidated balance sheet as of December 31, 2003. In January 2004, SER exercised the lease purchase option and acquired the power plant. See further discussion on FIN 46 in Note 1 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference. Additionally, during 2003, construction was completed on Termoelectrica de Mexicali, a 600-megawatt power plant near Mexicali, and the Elk Hills Power Project (Elk Hills), both of which commenced commercial operations in July 2003.

In August 2003, SER obtained approval from the appropriate state agencies to construct the Palomar Energy project, a 550-megawatt power plant in Escondido, California. In October 2003, SDG&E announced that it plans to purchase the power plant from SER when construction is completed in 2006 if the CPUC approves the purchase. On October 3, 2003 SER entered into a cost reimbursement and sharing agreement with SDG&E that became effective December 1, 2003.

In October 2002, SER purchased a 305-megawatt, coal-fired power plant (renamed Twin Oaks Power) from Texas-New Mexico Power Company for $120 million. SER has a five-year contract to sell substantially all of the output of the plant.

SEMPRA ENERGY LNG

In April 2003, SELNG completed its previously announced acquisition of the proposed Cameron LNG project from a subsidiary of Dynegy, Inc. The total cost of the project is expected to be $700 million. The project could begin commercial operations in 2007. FERC approval was granted on September 11, 2003. Other state and federal approvals required to commence construction are in progress.

In December 2003, in connection with plans to develop Energia Costa Azul, an LNG receiving terminal in Baja California, on the west coast of Mexico, 50 miles south of San Diego, SELNG and Shell International Gas Limited (Shell) announced plans to form a 50/50 joint venture to build, own and operate the $600 million facility. The terminal would be capable of supplying 1 billion cubic feet (bcf) of natural gas per day. Shell and SELNG would share the investment costs of the terminal equally and each would take 50 percent of the capacity in the terminal. 500 million cubic feet per day of natural gas from the terminal would be used to meet the growing energy demands in western Mexico. Any surplus gas from the facility would be used to provide new natural gas supplies for the southwestern United States. The proposed joint venture would combine the two separate Baja California LNG receiving terminals proposed by Shell and SELNG into a single project, significantly reducing the impact on the local environment. It is expected that construction would begin in 2004 with terminal operations commencing in 2007.

In connection with this project, Mexico's national environmental agency issued an environmental permit in April 2003. Three other significant permits, an operating permit from Mexico's Energy Regulatory Commission, a coastal zone use permit and a local land-use permit from the City of Ensenada, were granted in 2003. The permit to construct marine facilities is pending and is expected to be received in the near future.

See additional discussion concerning these projects in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 2 and 15 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

SEMPRA ENERGY INTERNATIONAL

SEI develops, operates and invests in energy-infrastructure systems. SEI has interests in natural gas and/or electric transmission and distribution projects in Argentina, Chile, Mexico, Peru and the eastern United States. SEI's interests in operations in South America are not consolidated and, therefore, are not included in these discussions.

During the third quarter of 2003, SEI recorded a $77 million before-tax write-down of the carrying value of the assets of Frontier Energy, a small North Carolina utility subsidiary, as a result of reductions in actual and previously anticipated sales of natural gas by the utility.

In the third quarter of 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico, with a pipeline built by PG&E Corporation that will connect to Arizona. The 30-inch pipeline can deliver up to 500 million cubic feet per day of natural gas to new generation facilities in Baja California, including SER's Termoelectrica de Mexicali power plant discussed above. Capacity on the pipeline is over 90 percent subscribed.

SEMPRA ENERGY SOLUTIONS

SES sells energy commodities and provides integrated energy-related products and services to commercial, industrial, government and institutional markets.

SEMPRA ENERGY FINANCIAL

SEF invests as a limited partner in affordable-housing properties. SEF's portfolio includes 1,300 properties throughout the United States, including Puerto Rico and the Virgin Islands. These investments are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also has invested in a limited partnership that produces synthetic fuel from coal. Whether SEF will invest in additional properties will depend on Sempra Energy's income tax position.

RATES AND REGULATION -- CALIFORNIA UTILITIES

Information concerning rates and regulations applicable to the California Utilities is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 1, 13 and 14 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

ENVIRONMENTAL MATTERS

Discussions about environmental issues affecting the company are included in Note 15 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference. The following additional information should be read in conjunction with those discussions.

Hazardous Substances

In 1994, the CPUC approved the Hazardous Waste Collaborative Memorandum account, allowing California's IOUs to recover their hazardous waste cleanup costs, including those related to Superfund sites or similar sites requiring cleanup. 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. Cleanup costs at sites related to electric generation were specifically excluded from the collaborative by the CPUC.

During the early 1900s, the California Utilities and their predecessors manufactured gas from coal or oil. The manufactured-gas plants (MGPs) often have become contaminated with the hazardous residues of the process. SoCalGas has identified 42 such sites at which it (together with other users as to 21 of these sites) may have cleanup obligations. Preliminary investigations, at a minimum, have been completed on 41 of the sites. As of December 31, 2003, 26 of these sites have been remediated, of which 20 have received certification from the California Environmental Protection Agency. At December 31, 2003, SoCalGas' estimated remaining investigation and remediation liability for the MGPs is $42.9 million. SDG&E identified three former MGPs, remediation of which was completed at two of the sites in 1998 and 2000. Closure letters have been received for the two sites. At December 31, 2003 estimated remaining remediation liability on the third site is $5.8 million.

SDG&E sold its fossil-fuel generating facilities in 1999. As a part of its due diligence for the sale, SDG&E conducted a thorough environmental assessment of the facilities. Pursuant to the sale agreements for such facilities, SDG&E and the buyers have apportioned responsibility for such environmental conditions generally based on contamination existing at the time of transfer and the cleanup level necessary for the continued use of the sites as industrial sites. While the sites are relatively clean, the assessments identified some instances of significant contamination, principally resulting from hydrocarbon releases, for which SDG&E has a cleanup obligation under the agreement. Total costs to perform the necessary remediation were estimated at $11 million at the time of sale. These costs were offset against the sales price for the facilities, together with other appropriate costs, and the remaining net proceeds were included in the calculation of customer rates. Remediation of the plants commenced in early 2001. During 2002, cleanup was completed at several minor sites at a cost of $0.4 million. In late 2002, additional assessments were started at the primary sites, where cleanup commenced in 2003 and is expected to be completed by 2005. In 2003, at a cost of $0.8 million, cleanup was completed at the site of a power plant that was sold in 1999. Remaining costs to remediate these sites are estimated at $8 million at December 31, 2003.

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

The company and certain subsidiaries are currently named as potentially responsible parties (PRPs) for one landfill site and two industrial waste disposal sites, from which releases have occurred, as described below.

At December 31, 2003, the company's estimated remaining investigation and remediation liability related to hazardous waste sites, including the MGPs, was $50.6 million, of which 90 percent is authorized to be recovered through the Hazardous Waste Collaborative mechanism. This estimated cost excludes remediation costs associated with SDG&E's former fossil-fuel power plants. The company believes that any costs not ultimately recovered through rates, insurance or other means will not have a material adverse effect on the company's consolidated results of operations or financial position.

Estimated liabilities for environmental remediation are recorded when amounts are probable and estimable. Amounts authorized to be recovered in rates under the Hazardous Waste Collaborative mechanism are recorded as a regulatory asset.

Electric and Magnetic Fields (EMFs)

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

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

Air and Water Quality

California's air quality standards are more restrictive than federal standards. However, as a result of the sale of the company's fossil-fuel generating facilities, the company's primary air-quality issue, compliance with these standards now has less significance to the company's operation, although that could change as SER owns and operates more generating facilities.

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

In connection with the issuance of operating permits, SDG&E and the other owners of SONGS previously reached agreement with the California Coastal Commission to mitigate the environmental damage to the marine environment attributed to the cooling-water discharge from SONGS Units 2 and 3. This mitigation program includes an enhanced fish-protection system, a 150-acre artificial kelp reef and restoration of 150 acres of coastal wetlands. In addition, the owners must deposit $3.6 million with the state for the enhancement of fish hatchery programs and pay for monitoring and oversight of the mitigation projects. SDG&E's share of the cost is estimated to be $34.0 million. These mitigation projects are expected to be completed in 2007. Through December 31, 2003, SONGS mitigation costs were recovered through the ICIP mechanism. SONGS mitigation costs incurred after December 31, 2003, will be capitalized and recovered from ratepayers over the remaining life of the SONGS units, subject to CPUC approval in Edison's general rate case. Additional information on SONGS cost recovery is provided in Note 13 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

OTHER MATTERS

Research, Development and Demonstration (RD&D)

The SoCalGas RD&D portfolio is focused in five major areas: operations, utilization systems, power generation, public interest and transportation. Each of these activities provides benefits to customers and society by providing more cost-effective, efficient natural gas equipment with lower emissions, increased safety, and reduced operating costs. The CPUC has authorized SoCalGas to recover its operating costs associated with RD&D. SoCalGas' annual RD&D costs have averaged $6.9 million over the past three years.

For 2003, the CPUC authorized SDG&E to fund $1.2 million and $5.6 million for its natural gas and electric RD&D programs, respectively, including $5.6 million to the CEC for its PIER (Public Interest Energy Research) Program. SDG&E's annual RD&D costs have averaged $5.7 million over the past three years.

Employees of Registrant

As of December 31, 2003, the company had 12,807 employees, compared to 12,197 at December 31, 2002.

Labor Relations

Field, technical and most clerical employees at SoCalGas are represented by the Utility Workers' Union of America or the International Chemical Workers' Council. The collective bargaining agreement for field, technical and most clerical employees at SoCalGas covering wages, hours, working conditions, medical and various benefit plans is in effect through December 31, 2004.

Certain employees at SDG&E are represented by the Local 465 International Brotherhood of Electrical Workers. The current contract runs through August 31, 2004. At some of its field job sites, SES employs mechanics who are represented by the International Union of Operating Engineers, Local 501. One collective bargaining agreement runs through November 1, 2006 and the other expires on July 7, 2007.

ITEM 2. PROPERTIES

Electric Properties - SDG&E

SDG&E's interest in SONGS is described in "Electric Resources" herein. At December 31, 2003, SDG&E's electric transmission and distribution facilities included substations, and overhead and underground lines. The electric facilities are located in San Diego, Imperial and Orange counties and in Arizona, and consist of 1,805 miles of transmission lines and 21,353 miles of distribution lines. Periodically, various areas of the service territory require expansion to accommodate customer growth.

Natural Gas Properties - California Utilities

At December 31, 2003, the California Utilities' natural gas facilities included 3,014 miles of transmission and storage pipeline, 54,518 miles of distribution pipeline and 51,672 miles of service piping. They also included 13 transmission compressor stations and 4 underground storage reservoirs, with a combined working capacity of 122 bcf.

Energy Properties - Other

At December 31, 2003, Sempra Energy completed the construction of three additional power plants and commenced operations in California, Arizona and Mexico. For additional information, see Notes 2 and 3 of the notes to Consolidated Financial Statements of the 2003 Annual Report to Shareholders, which is incorporated by reference from Item 8 herein.

At December 31 2003, SEI's operations in Mexico included 1,465 miles of distribution pipeline, 163 miles of transmission pipeline and one compressor station.

At December 31 2003, the company's two small natural gas utilities located in the eastern United States owned 166 miles of transmission lines and 206 miles of distribution lines.

Other Properties

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

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

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

Global leases office facilities at various locations in the U.S, Mexico and Europe with the leases ending from 2004 to 2009. SELNG owns land to develop a LNG receiving terminal in Baja California, Mexico. SELNG also has a land lease to develop a LNG receiving terminal in Hackberry, Louisiana. The lease expires in February 2005 and has five five-year renewal options remaining.

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

ITEM 3. LEGAL PROCEEDINGS

Except for the matters referred to in Notes 13, 14 and 15 of the notes to Consolidated Financial Statements incorporated by reference in Item 8 or referred to elsewhere in "Management's Discussion and Analysis of Financial Condition and Results of Operations" incorporated by reference in this Annual Report, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

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

Sempra Energy common stock is traded on the New York and Pacific stock exchanges. At January 31, 2004, there were 60,000 registered holders and record holders of the company's common stock. The quarterly common stock information required by Item 5 is included in the schedule of Quarterly Financial Data of the 2003 Annual Report to Shareholders, which is incorporated by reference.

ITEM 6. SELECTED FINANCIAL DATA

(Dollars in millions) At December 31, or for the years then ended - ---- ------------ ------------ ------------ ------------ ------------ ------------ -------- 2003 2002 2001 2000 1999 ------- ------- ---- --- ------- -------

~~Income Statement Data: Operating revenues $ 7,887 $ 6,048 $ 7,730 $ 6,760 $ 5,360 Operating income $ 939 $ 987 $ 997 $ 884 $ 763 Net income $ 649 $ 591 $ 518 $ 429 $ 394 Balance Sheet Data: Total assets $22,009 $20,242 $17,476 $17,850 $13,312 Long-term debt $ 3,841 $ 4,083 $ 3,436 $ 3,268 $ 2,902 Short-term debt (a) $ 1,461 $ 851 $ 1,117 $ 936 $ 337 Shareholders' equity $ 3,890 $ 2,825 $ 2,692 $ 2,494 $ 2,986 Per Common Share Data: Income before extraordinary item and cumulative effect of changes in accounting~~

~~principles per common share: Basic $ 3.29 $ 2.80 $ 2.54 $ 2.06 $ 1.66 Diluted $ 3.24 $ 2.79 $ 2.52 $ 2.06 $ 1.66 Income before cumulative effect of changes in accounting principles per common share: Basic $ 3.29 $ 2.88 $ 2.54 $ 2.06 $ 1.66 Diluted $ 3.24 $ 2.87 $ 2.52 $ 2.06 $ 1.66 Net income per common share: Basic $ 3.07 $ 2.88 $ 2.54 $ 2.06 $ 1.66 Diluted $ 3.03 $ 2.87 $ 2.52 $ 2.06 $ 1.66 Dividends declared $ 1.00 $ 1.00 $ 1.00 $ 1.00 $ 1.56 Book value $ 17.17 $ 13.79 $ 13.16 $ 12.35 $ 12.58 (a) Includes long term debt due within one year.~~

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

in the 2003 Annual Report to Shareholders, which is incorporated by reference.

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

The information required by Item 7 is incorporated by reference from pages 1 through 38 of the 2003 Annual Report to Shareholders.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by Item 7A is incorporated by reference from pages 30 through 33 of the 2003 Annual Report to Shareholders.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by Item 8 is incorporated by reference from pages 42 through 129 of the 2003 Annual Report to Shareholders. Item 15(a)1 includes a listing of financial statements included in the 2003 Annual Report to Shareholders.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

The company has designed and maintains disclosure controls and procedures to ensure that information required to be disclosed in the company's reports under the Securities Exchange Act of 1934 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 has investments in unconsolidated entities that it does not control or manage and, consequently, its disclosure controls and procedures with respect to these entities are necessarily substantially more limited than those it maintains with respect to its consolidated subsidiaries.

Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, the company as of December 31, 2003 has evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures. Based on that evaluation, the company's Chief Executive Officer and Chief Financial Officer have concluded that the controls and procedures are effective.

There have been no significant changes in the company's internal controls or in other factors that could significantly affect the internal controls subsequent to the date the company completed its evaluation.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required on Identification of Directors is incorporated by reference from "Election of Directors" in the Proxy Statement prepared for the May 2004 annual meeting of shareholders. The information required on the company's executive officers is provided below.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age*	Position
Stephen L. Baum	62	Chairman, Chief Executive Officer and President
Donald E. Felsinger	56	Group President, Sempra Energy Global Enterprises
Edwin A. Guiles	54	Group President, Sempra Energy Utilities
M. Javade Chaudhri	51	Executive Vice President and General Counsel
Neal E. Schmale	57	Executive Vice President and Chief Financial Officer
Frank H. Ault	59	Senior Vice President and Controller
Frederick E. John	57	Senior Vice President, External Affairs and Communications
G. Joyce Rowland	49	Senior Vice President, Human Resources

* As of December 31, 2003.

Each Executive Officer has been an officer of the company or one of its subsidiaries for more than five years, with the exception of Mr. Chaudhri. Prior to joining the company in 2003, Mr. Chaudhri was Senior Vice President and General Counsel of Gateway, Inc.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference from "Election of Directors" and "Executive Compensation" in the Proxy Statement prepared for the May 2004 annual meeting of shareholders.

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

Securities Authorized for Issuance Under Equity Compensation Plans

Information regarding securities authorized for issuance under equity compensation plans as required by Item 12 is incorporated by reference from "Share Ownership" and "Equity Compensation Plans" in the Proxy Statement prepared for the May 2004 annual meeting of shareholders.

See additional discussion of stock-based compensation in Note 9 of the notes to Consolidated Financial Statements of the 2003 Annual Report to Shareholders, which is incorporated by reference.

Security Ownership of Certain Beneficial Owners

The security ownership information required by Item 12 is incorporated by reference from "Share Ownership" in the Proxy Statement prepared for the May 2004 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information regarding principal accountant fees and services as required by Item 14 is incorporated by reference from "Proposal 3: Ratification of Independent Auditors" in the Proxy Statement prepared for the May 2004 annual meeting of shareholders.

PART IV

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

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

1. Financial statements

*Incorporated by reference from the indicated pages of the 2003 Annual Report to Shareholders.

2. Financial statement schedules

The following document may be found in this report at the indicated page number.

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

3. Exhibits

See Exhibit Index on page 44 of this report.

(b) Reports on Form 8-K

The following reports on Form 8-K were filed after September 30, 2003:

Current Report on Form 8-K filed October 9, 2003, announcing the execution of an underwriting agreement for the issuance and sale of common stock and reporting several recent developments related to credit rating changes, litigation, and other events.

Current Report on Form 8-K filed November 6, 2003, filing as an exhibit Sempra Energy's press release of November 6, 2003, giving the financial results for the three months ended September 30, 2003.

Current Report on Form 8-K filed December 31, 2003, to update information on the August 25, 2003 CPUC decision regarding the allocation of profits from SDG&E's intermediate-term purchase power contracts. Updates when the Court of Appeals will have a decision on the petition submitted by an advocacy group for small consumers.

Current Report on Form 8-K filed February 24, 2004, filing as an exhibit Sempra Energy's press release of February 24, 2004, giving the financial results for the three months ended December 31, 2003.

INDEPENDENT AUDITORS' CONSENT AND REPORT ON SCHEDULE

To the Board of Directors and Shareholders of Sempra Energy:

We consent to the incorporation by reference in Registration Statement Numbers 333-51309, 333-52192, 333-77843, 333-70640 and 333-103588 on Form S-3 and Registration Statement Numbers 333-56161, 333-50806 and 333-49732 on Form S-8 of Sempra Energy of our report dated February 23, 2004, incorporated by reference in this Annual Report on Form 10-K of Sempra Energy for the year ended December 31, 2003.

Our audits of the financial statements referred to in our aforementioned report also included the financial statement schedule of Sempra Energy, listed in Item 15. This financial statement schedule is the responsibility of the company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 24, 2004

Schedule I -- CONDENSED FINANCIAL INFORMATION OF PARENT

SEMPRA ENERGY

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

Years ended December 31,	2003	2002	2001
Other income	$ 126	$ 52	$ 52
Interest expense	(187)	(134)	(130)
Trust preferred distributions	(9)	(18)	(18)
Operating expenses	(21)	(14)	(25)
Income tax benefits	57	38	55
Loss before subsidiary earnings	(34)	(76)	(66)
Subsidiary earnings before extraordinary item and cumulative effect of changes in accounting principles	729	651	584
Income before extraordinary item and cumulative effect of changes in accounting principles	695	575	518
Extraordinary item, net of tax	--	16	--
Income before cumulative effect of changes in accounting principles, net of tax	695	591	518
Cumulative effect of changes in accounting principles, net of tax	(46)	--	--
Net income	$ 649	$ 591	$ 518
Weighted average number of			

~~shares outstanding (thousands):~~
~~Basic 211,740 205,003 203,593~~
~~======== ======== ========~~
~~Diluted 214,482 206,062 205,338~~
~~======== ======== ========~~
~~Income before extraordinary item and cumulative effect of changes in accounting principles per share of common stock~~
~~Basic $ 3.29 $ 2.80 $ 2.54~~
~~======== ======== ========~~
~~Diluted $ 3.24 $ 2.79 $ 2.52~~
~~======== ======== ========~~
~~Income before cumulative effect of changes in accounting principles per share of common stock~~
~~Basic $ 3.29 $ 2.88 $ 2.54~~
~~======== ======== ========~~
~~Diluted $ 3.24 $ 2.87 $ 2.52~~
~~======== ======== ========~~
~~Net income per share of common stock~~
~~Basic $ 3.07 $ 2.88 $ 2.54~~
~~======== ======== ========~~
~~Diluted $ 3.03 $ 2.87 $ 2.52~~
~~======== ======== ========~~

SEMPRA ENERGY

Condensed Balance Sheets
(Dollars in millions)

	December 31, 2003	December 31, 2002
Assets:		
Cash and cash equivalents	$ 59	$ 3
Due from affiliates	52	72
Other current assets	43	7
Total current assets	154	82
Investments in subsidiaries	5,518	4,995
Due from affiliates	2,521	1,730
Other assets	435	388
Total assets	$ 8,628	$ 7,195
Liabilities and Shareholders' Equity:		
Current portion of long-term debt	$ 525	$ 2
Income taxes payable	323	247
Due to affiliates	1,403	1,500
Other current liabilities	178	157
Total current liabilities	2,429	1,906
Long-term debt	1,900	2,043
Due to affiliate	200	--
Other long-term liabilities	209	421
Shareholders' equity	3,890	2,825
Total liabilities and shareholders' equity	$ 8,628	$ 7,195

SEMPRA ENERGY

Condensed Statements of Cash Flows
(Dollars in millions)

Years ended December 31,	2003	2002	2001
Net cash provided by (used in) operating activities	$ (80)	$ 144	$ (253)
Dividends received from subsidiaries	250	100	340
Expenditures for property, plant and equipment	(4)	(12)	(35)
Increase in investments and other assets	--	(20)	(30)
Cash provided by investing activities	246	68	275
Common stock dividends paid	(207)	(205)	(203)
Repurchase of common stock	(6)	(16)	(1)
Sale of common stock	549	13	41
Issuances of long-term debt	400	600	581
Payment on long term debt	--	(26)	(84)
Loans to affiliates -- net	(842)	(628)	(345)
Other	(4)	(19)	(2)
Cash used in financing activities	(110)	(281)	(13)
Increase (decrease) in cash and cash equivalents	56	(69)	9

~~Cash and cash equivalents, January 1 3 72 63~~

~~Cash and cash equivalents, December 31~~	~~$ 59~~	~~$ 3~~	~~$ 72~~

SEMPRA ENERGY
Note to Condensed Financial Statements

Long-term Debt

(Dollars in millions)	December 31, 2003	December 31, 2002
Other long-term debt		
5.60% equity units May 17, 2007	$ 600	$ 600
Notes payable at variable rates after a fixed-to-floating rate swap (2.49% at December 31, 2003) July 1, 2004	500	500
7.95% Notes March 1, 2010	500	500
6.0% Notes due February 1, 2013	400	--
6.95% Notes December 1, 2005	300	300
Employee Stock Ownership Plan		
Bonds at 7.375% November 1, 2014	82	82
Bonds at variable rates (1.65% at December 31, 2003) November 1, 2014	19	19
Capitalized leases	3	5
Market value adjustments for interest rate swaps - net (expires July 1, 2004)	23	42
Total	$2,427	$2,048
Less:		
Current portion of long-term debt	525	2
Unamortized discount on long-term debt	2	3
	527	5
Total	$1,900	$2,043

Excluding market value adjustments for interest-rate swaps, maturities of long-term debt are $502 million in 2004, $301 million in 2005, $600 million in 2007 and $1 billion thereafter.

Additional information on Sempra Energy's long-term debt is provided in Note 5 of the notes to Consolidated Financial Statements in the 2003 Annual Report to Shareholders, which is incorporated by reference.

SIGNATURES

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

SEMPRA ENERGY

By: /s/ Stephen L. Baum

Stephen L. Baum
Chairman, 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:~~		
~~Stephen L. Baum Chairman, President and Chief Executive Officer~~	~~/s/ Stephen L. Baum~~	~~February 20, 2004~~
~~Principal Financial Officer:~~		
~~Neal E. Schmale Executive Vice President and Chief Financial Officer~~	~~/s/ Neal E. Schmale~~	~~February 20, 2004~~
~~Principal Accounting Officer:~~		
~~Frank H. Ault Senior Vice President and Controller~~	~~/s/ Frank H. Ault~~	~~February 20, 2004~~
~~Directors:~~		
~~Stephen L. Baum, Chairman~~	~~/s/ Stephen L. Baum~~	~~February 20, 2004~~
~~Hyla H. Bertea, Director~~	~~/s/ Hyla H. Bertea~~	~~February 20, 2004~~
~~James G. Brocksmith, Jr., Director~~	~~/s/ James G. Brocksmith, Jr.~~	

~~February 20, 2004~~
~~Herbert L. Carter, Director~~
~~/s/ Herbert L. Carter~~
~~February 20, 2004~~
~~Richard A. Collato, Director~~
~~/s/ Richard A. Collato~~
~~February 20, 2004~~
~~Wilford D. Godbold, Jr., Director~~
~~/s/ Wilford D. Godbold, Jr.~~
~~February 20, 2004~~
~~William D. Jones, Director~~
~~/s/ William D. Jones~~
~~February 20, 2004~~
~~Richard G. Newman, Director~~
~~/s/ Richard G. Newman~~
~~February 20, 2004~~
~~William G. Ouchi, Director~~
~~/s/ William G. Ouchi~~
~~February 20, 2004~~
~~William C. Rusnack, Director~~
~~/s/ William C. Rusnack~~
~~February 20, 2004~~
~~William P. Rutledge, Director~~
~~/s/ William P. Rutledge~~
~~February 20, 2004~~
~~Thomas C. Stickel, Director~~
~~/s/ Thomas C. Stickel~~
~~February 20, 2004~~
~~Diana L. Walker, Director~~
~~/s/ Diana L. Walker~~
~~February 20, 2004~~

EXHIBIT INDEX

The Forms 8, 8-B/A, 8-K, S-4, 10-K and 10-Q referred to herein were filed under Commission File Number 1-14201 (Sempra Energy), Commission File Number 1-40 (Pacific Enterprises), Commission File Number 1-3779 (San Diego Gas & Electric), Commission File Number 1-1402 (Southern California Gas Company), Commission File Number 1-11439 (Enova Corporation) and/or Commission File Number 333-30761 (SDG&E Funding LLC).

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

Exhibit 1 -- Underwriting Agreements

Enova Corporation and San Diego Gas & Electric Company
- ---

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

Exhibit 3 -- Bylaws and Articles of Incorporation

Bylaws

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

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

Articles of Incorporation

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

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

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

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

Enova Corporation and San Diego Gas & Electric Company
- ---

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

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

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

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

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

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

Pacific Enterprises and Southern California Gas
- ---

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

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

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

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

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

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

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

4.14 Supplemental Indenture of Southern California Gas Company to Manufacturers Hanover Trust Company of California, successor to Wells Fargo Bank, National Association, and Crocker National Bank as Successor Trustee dated as of May 18, 1984 (Southern California Gas Company 1984 Form 10-K, Exhibit 4.29).

4.15 Supplemental Indenture of Southern California Gas Company to Bankers Trust Company of California, N.A., successor to Wells Fargo Bank, National Association dated as of January 15, 1988 (Pacific Enterprises 1987 Form 10-K, Exhibit 4.11).

4.16 Supplemental Indenture of Southern California Gas Company to First Trust of California, National Association, successor to Bankers Trust Company of California, N.A. dated as of August 15, 1992 (Registration Statement No. 33-50826 filed by Southern California Gas Company on August 13, 1992, Exhibit 4.37).

4.17 Supplemental Indenture of Southern California Gas Company to U.S. Bank, N.A., successor to First Trust of California, N.A., dated as of October 1, 2002.

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

Sempra Energy
- -------------
10.01 Energy Purchase Agreement between Sempra Energy Resources and the California Department of Water Resources, executed May 4, 2001 (2001 Form 10-K, Exhibit 10.01).

10.02 Form of Employment Agreement between Sempra Energy and Stephen L. Baum (September 30, 2002 Form 10-Q, Exhibit 10.1).

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

10.04 Form of Employment Agreement between Sempra Energy and Donald E. Felsinger (September 30, 2002 Form 10-Q, Exhibit 10.2).

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

Enova Corporation and San Diego Gas & Electric Company
- ---
10.06 Operating Agreement between San Diego Gas & Electric and the California Department of Water Resources dated April 17, 2003.

10.07 Servicing Agreement between San Diego Gas & Electric and the California Department of Water Resources dated December 19, 2002.

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

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

Compensation

Sempra Energy

10.10 2003 Sempra Energy Executive Incentive Plan B.

10.11 2003 Executive Incentive Plan (June 30, 2003 Form 10-Q, Exhibit 10.1).

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

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

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

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

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

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

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

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

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

Financing

Enova Corporation and San Diego Gas & Electric

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

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

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

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

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

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

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

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

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

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

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

Natural Gas Transportation

Enova Corporation and San Diego Gas & Electric
- ---

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

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

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

Nuclear

Enova Corporation and San Diego Gas & Electric
- ---

10.35 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).

10.36 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.35 herein)(1994 SDG&E Form 10-K, Exhibit 10.56).

10.37 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 10.35 herein)(1994 SDG&E Form 10-K, Exhibit 10.57).

10.38 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 10.35 herein)(1996 SDG&E Form 10-K, Exhibit 10.59).

10.39 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 10.35 herein)(1996 SDG&E Form 10-K, Exhibit 10.60).

10.40 Fifth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generation Station (see Exhibit 10.35 herein)(1999 SDG&E Form 10-K, Exhibit 10.26).

10.41 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 10.35 herein)(1999 SDG&E Form 10-K, Exhibit 10.27).

10.42 Seventh Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated December 24, 2003 (see Exhibit 10.35 herein).

10.43 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).

10.44 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 10.43 herein)(1996 Form 10-K, Exhibit 10.62).

10.45 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 10.43 herein)(1996 Form 10-K, Exhibit 10.63).

10.46 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 10.43 herein)(1999 SDG&E Form 10-K, Exhibit 10.31).

10.47 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 10.43 herein)(1999 SDG&E Form 10-K, Exhibit 10.32).

10.48 Fifth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated December 24, 2003 (see Exhibit 10.43 herein).

10.49 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).

10.50 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, 2003, 2002, 2001, 2000, and 1999.

Exhibit 13 -- Annual Report to Security Holders

13.01 Sempra Energy 2003 Annual Report to Shareholders. (Such report, except for the portions thereof which are expressly incorporated by reference in this Annual Report, is furnished for the information of the Securities and Exchange Commission and is not to be deemed "filed" as part of this Annual Report).

Exhibit 21 -- Subsidiaries

21.01 Schedule of Significant Subsidiaries at December 31, 2003.

Exhibit 23 -- Independent Auditors' Consent, page 38.

Exhibit 31 -- Section 302 Certifications

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

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

Exhibit 32 -- Section 906 Certifications

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

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

GLOSSARY

AB	California Assembly Bill
AB X1	A California Assembly bill authorizing the California Department of Water Resources to purchase energy for California consumers.
AEG	Atlantic Electric & Gas Limited
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
APB	Accounting Principles Board
APS	Arizona Public Service Co.
ARB	Accounting Research Bulletin
BCAP	Biennial Cost Allocation Proceeding
Bcf	One Billion Cubic Feet (of natural gas)
Calpine	Calpine Corporation
CEC	California Energy Commission
CEMA	Catastrophic Event Memorandum Account
CFTC	Commodity Futures Trading Commission
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharge
DA	Direct Access
DGN	Distribuidora de Gas Natural
DOE	Department of Energy
DSM	Demand-Side Management
DWR	Department of Water Resources
Edison	Southern California Edison Company
EITF	Emerging Issues Task Force
El Paso	El Paso Energy Corp.
Elk Hills	Elk Hills Power Project
EG	Electric Generation
EMFs	Electric and Magnetic Fields

ERMG	Energy Risk Management Group
ERMOC	Energy Risk Management Oversight Committee
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
FSP	FASB Staff Position
GCIM	Gas Cost Incentive Mechanism
GIR	Gas Industry Restructuring
Global	Sempra Energy Global Enterprises
HOA	Heads of Agreement
ICIP	Incremental Cost Incentive Pricing
IID	Imperial Irrigation District
Intertie	Pacific Intertie
IOUs	Investor-Owned Utilities
IRS	Internal Revenue Service
ISO	Independent System Operator
kWh	Kilowatt Hour
LIFO	Last-In First-Out inventory costing method
LNG	Liquefied Natural Gas
Luz del Sur	Luz del Sur S.A.A.
MGPs	Manufactured-Gas Plants
mmbtu	Million British Thermal Units (of natural gas)
Moody's	Moody's Investor Services, Inc.
MW	Megawatt
NRC	Nuclear Regulatory Commission
Occidental	Occidental Energy Ventures Corporation
OIR	Order Instituting Ratemaking

OPEC	Organization of the Petroleum Exporting Countries
ORA	Office of Ratepayer Advocates
OTC	Over the counter
PBR	Performance-Based Regulation
PE	Pacific Enterprises
PG&E	PG&E Corporation
PGA	Purchased Gas Balancing Account
PGE	Portland General Electric Company
PIER	Public Interest Energy Research
PPA	Power Purchase Agreement
PRPs	Potentially Responsible Parties
PSEG	PSEG Global
PX	Power Exchange
QFs	Qualifying Facilities
RD&D	Research, Development and Demonstration
RFP	Request for Proposals
ROE	Return on Equity
ROR	Return on Ratebase
S&P	Standard & Poor's
SDG&E	San Diego Gas & Electric Company
SEC	Securities and Exchange Commission
SELNG	Sempra Energy LNG Corp.
SEF	Sempra Energy Financial
SEI	Sempra Energy International
SER	Sempra Energy Resources
SES	Sempra Energy Solutions
SET	Sempra Energy Trading
SFAS	Statement of Financial Accounting Standards
Shell	Shell International Gas Limited

SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
Southwest Powerlink	A transmission line connecting San Diego to Phoenix and intermediate points.
SPEs	Special Purpose Entities
Sunat	Peruvian tax authorities
TDM	Termoelectrica de Mexicali
The Act	Medicare Prescription Drug Improvement Modernization Act
The Board	Sempra Energy's Board of Directors
Trust	ESOP Trust
UCAN	Utility Consumers Action Network
VaR	Value at Risk
VIEs	Variable Interest Entities

EXHIBIT 10.06

SDG&E OPERATING AGREEMENT
Between

STATE OF CALIFORNIA
DEPARTMENT OF WATER RESOURCES
And
SAN DIEGO GAS & ELECTRIC COMPANY

THIS AGREEMENT HAS BEEN FILED WITH AND APPROVED BY THE CALIFORNIA PUBLIC UTILITIES COMMISSION ("COMMISSION") FOR USE BETWEEN THE STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES ("DWR") AND SAN DIEGO GAS & ELECTRIC COMPANY ("UTILITY").

Execution Date: April 16 , 2003
Date of Commission Approval:
Effective Date:

OPERATING AGREEMENT

This OPERATING AGREEMENT (this "Agreement") is between the State of California Department of Water Resources ("DWR"), acting solely under the authority and powers granted by AB1X, codified as Sections 80000 through 80270 of the Water Code, and not under its powers and responsibilities with respect to the State Water Resources Development System, and San Diego Gas & Electric Company, a California corporation ("Utility"). DWR and Utility are sometimes collectively referred to herein as the "Parties" and individually referred to as a "Party." Unless otherwise noted, all capitalized terms shall have the meanings set forth in Article I of this Agreement.

R E C I T A L S

WHEREAS, under the Act, DWR has entered into a number of long-term power purchase agreements for the purpose of providing the net short requirements to the retail ratepayers of the State's electrical corporations, including Utility; and

WHEREAS, the Contract Allocation Order of the Commission provides that such long-term power purchase agreements are to be operationally allocated among the State's electrical corporations, including Utility; solely for the purpose of causing the State's electrical corporations to perform certain specified functions on behalf of DWR, as DWR's limited agent, including dispatching, scheduling, billing and settlements functions, and to sell surplus energy, all as such functions relate to those certain power purchase agreements that are operationally allocated to each electrical corporation under the Contract Allocation Order; and

WHEREAS, DWR wishes to provide for the performance of such functions under the Allocated Contracts by Utility on behalf of DWR in accordance with such long-term power purchase agreements as provided in this Agreement; and

WHEREAS, consistent with the Contract Allocation Order, DWR will retain legal and financial obligations, together with ongoing responsibility for any other functions not explicitly provided in this Agreement to be performed by Utility, with respect to each of the Allocated Contracts and it is the intent of DWR and the Utility that the provisions of this Agreement will not constitute an "assignment" of the Allocated Contracts to Utility.

NOW, THEREFORE, in consideration of the mutual obligations of the Parties, the Parties agree as follows:

ARTICLE I
DEFINITIONS

Section 1.01. Definitions. The following terms shall have the respective meanings in this Agreement:

The following terms, when used herein (and in the attachments hereto) with initial capitalization, shall have the meaning specified in this Section 1.01. Certain additional terms are defined in the attachments hereto. The singular shall include the plural and the masculine shall include the feminine and neuter, and vice versa. "Includes" or "including" shall mean "including without limitation." References to a section or attachment shall mean a section or attachment of this Agreement, as the case may be, unless the context requires otherwise, and reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made (except as otherwise specifically provided herein). Unless the context otherwise requires, references to Applicable Laws or Applicable Tariffs shall be deemed references to such laws or tariffs as they may be amended, replaced or restated from time to time. References to the time of day shall be deemed references to such time as measured by prevailing Pacific time.

"Act" means Chapter 4 of Statutes of 2001 (Assembly Bill 1 of the First 2001-02 Extraordinary Session) of the State of California, as amended.

"Agreement", means this Operating Agreement, together with all attached Schedules, Exhibits and Attachments, as such may be amended from time to time as evidenced by a written amendment executed by the Parties.

"Allocated Contracts" means the long-term power purchase agreements operationally allocated to Utility under the Contract Allocation Order, without legal and financial assignment of such agreements to Utility, as provided in Schedule 1 attached hereto.

"Allocated Power" means all power and energy, including the use of such power or energy as ancillary services, delivered or to be delivered under the Contracts.

"Applicable Commission Orders" means such rules, regulations, decisions, opinions or orders as the Commission may lawfully issue or promulgate from time to time, which relate to the subject matter of this Agreement.

"Applicable Law" means the Act, Applicable Commission Orders and any other applicable statute, constitutional provision, rule, regulation, ordinance, order, decision or code of a Governmental Authority.

"Applicable Tariffs" means Utility's tariffs, including all rules, rates, schedules and preliminary statements, governing electric energy service to Utility's customers in its service territory, as filed with and approved by the Commission and, if applicable, the Federal Energy Regulatory Commission.

"Assign(s)" shall have the meaning set forth in Section 14.01.

"Bonds" shall have the meaning set forth in the Rate Agreement.

"Bond Charges" shall have the meaning set forth in the Rate Agreement.

"Business Day" means the regular Monday through Friday weekdays which are customary working days, excluding holidays, as established by Applicable Tariffs.

"Commission" means the California Public Utilities Commission.

"Confidential Information" shall have the meaning set forth in Section 11.01(c).

"Contracts" means the Allocated Contracts.

"Contract Allocation Order" means Decision 02-09-053 of the Commission, issued on September 19, 2002, as such Decision may be modified, revised, amended, supplemented or superseded from time to time by the Commission.

"DWR Power" shall have the same meaning set forth in the Servicing Arrangement with such amendments to incorporate the Settlement Principles for Remittances and Surplus Revenues as provided in Exhibit C of this Agreement.

"DWR Revenues" means those amounts required to be remitted to DWR by Utility in accordance with this Agreement and as further provided in the Servicing Arrangement.

"Effective Date" means the effective date in accordance with Section 14.13, as such date is set forth on the cover page hereof.

"Fund" means the Department of Water Resources Electric Power Fund established by Section 80200 of the California Water Code.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not require the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the Western Electric Coordinating Council region.

"Governmental Authority" means any nation or government, any state or other political subdivision thereof, and any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to a government, including the Commission.

"Governmental Program" means any program or directive established by Applicable Law which directly or indirectly affects the rights or obligations of the Parties under this Agreement and which obligates or authorizes DWR to make payments or give credits to customers or other third parties under such programs or directives.

"ISO" means the California Independent System Operator Corporation.

"Order" means Decision 02-12-069 of the Commission, issued on December 19, 2002 as such decision may be amended or supplemented from time to time by the Commission.

"Power Charges" shall have the meaning set forth in the Rate Agreement.

"Priority Long Term Power Contract" shall have the meaning set forth in the Rate Agreement.

"Rate Agreement" means the Rate Agreement between DWR and the Commission adopted by the Commission on February 21, 2001 in Decision 02-02-051.

"Remittance" means a payment by Utility to DWR or its Assign(s) in accordance with the Servicing Arrangement.

"Servicing Arrangement" means the First Amended and Restated Servicing Agreement, dated March 29, 2002, between DWR and Utility, as amended.

"Supplier" means those certain third parties who are supplying power pursuant to the Contracts.

"Term" means term provided in Section 2.05 hereof.

"URG" means utility-retained generation, including without limitation Utility's portfolio of generation resources and power purchase agreements prior to or after the Effective Date by Utility.

Section 1.02. Undefined Terms. Capitalized terms not otherwise defined in Section 1.01 herein shall have the meanings set forth in the Act or the Servicing Arrangement.

ARTICLE II
OPERATIONAL ALLOCATION OF POWER PURCHASE AGREEMENTS; MANAGEMENT OF THE CONTRACTS; ALLOCATED POWER; TERM

Section 2.01. Operational Allocation and Management of Power Purchase Agreements. On behalf of DWR, as its limited agent, Utility will perform certain day-to-day scheduling and dispatch functions, billing and settlements and surplus energy sales and certain other tasks with respect to the Allocated Contracts, as more fully set forth in this Agreement.

As further provided in Contract Administration and Performance Test Monitoring Protocols set forth in Exhibit E, DWR will continue to monitor and audit the Supplier performance under the Contracts. Upon development of a mutually agreeable plan, Utility will monitor the performance of Suppliers, as further provided in Exhibit E, subject, however, to DWR's right but not the obligation to audit and monitor all functions contemplated to be performed by Utility, all as further provided in this Agreement.

Section 2.02. Standard of Contract Management.

(a) Utility agrees to perform the functions specified in this Agreement relating to the Allocated Contracts in a commercially reasonable manner, exercising Good Utility Practice, and in a fashion reasonably designed to serve the overall best interests of retail electric customers. Utility shall provide to DWR such information specifically provided in Exhibit F hereto to facilitate DWR's verification of Utility's compliance with this Section 2.02. In addition, the Parties acknowledge that DWR is not subject to the Commission's jurisdiction, and the Parties agree that none of the provisions of this Agreement, including Section 13.04 herein, shall be interpreted to subject DWR to the Commission's jurisdiction or authority.

(b) To the extent requested by Utility, DWR shall provide evidence in Commission proceedings describing Utility's and DWR's performance, rights and obligations under this Agreement.

(c) DWR acknowledges the Commission's exclusive authority over whether the Utility has managed Allocated Power available under the Contracts in a just and reasonable manner and DWR and Utility agrees that none of the provisions of this Agreement shall be interpreted to reduce, diminish, or otherwise limit the scope of any Commission authority or to give DWR any authority over such matters.

(d) The Utility acknowledges DWR's separate and independent right to evaluate and enforce Utility's commercial performance under this Agreement.

(g) Utility agrees to provide any information not otherwise required herein that is reasonably necessary to allow DWR to exercise its rights in subsection (d) above, provided that all such information shall be used solely for the purposes of exercising such rights.

Section 2.03. Good Faith. Each Party hereby covenants that it shall perform its actions, obligations and duties in connection with this Agreement in good faith.

Section 2.04. DWR Power. During the term of this Agreement, the electric power and energy, including but not limited to capacity, and output, or any of them from the Contracts delivered to retail end-use customers in Utility's service area shall constitute DWR Power for all purposes of the Servicing Arrangement. Utility shall arrange for transmission service to accommodate surplus sales to the extent that transmission service is available and cost effective, all as further provided in Exhibit A.

Section 2.05. Term.

(a) The Term of this Agreement shall commence on the Effective Date and shall terminate on the earlier of (a) the termination of the Servicing Arrangement, or (b) the termination of this Agreement by DWR upon ninety days' written notice to Utility, or (c) upon consultation with the Commission, the termination of the Agreement by DWR upon reasonable written notice to Utility no shorter than 30 days, or (d) pursuant to Article VII hereof, the termination of this Agreement by a non-defaulting Party after an Event of Default. In addition, this Agreement will terminate as to each Contract that terminates in accordance with its terms. DWR agrees to notify Utility as to the termination of each Contract as provided in Section 5.01(e) hereof.

(b) If an event occurs which has the effect of materially altering and materially adversely impacting the economic position of the Parties or either of them under this Agreement, then the affected Party may, by written notice, request that the Commission approve amendments to this Agreement or other arrangements incidental to this Agreement as necessary to preserve or restore the economic position under this Agreement held by the affected Party immediately prior to such event. Such notice shall describe the event and shall include reasonable particulars as to the manner and extent to which the economic position of the party giving notice has been adversely affected.

ARTICLE III
LIMITED AGENCY / NO ASSIGNMENT

Section 3.01. Limited Agency. Utility is hereby appointed as DWR's agent for the limited purposes set forth in this Agreement. Utility shall not be deemed to be acting, and shall not hold itself out, as agent for DWR for any purpose other than those described in this Agreement. Utility's duties and obligations shall be limited to those duties and obligations that are specified in this Agreement.

Section 3.02. No Assignment. DWR shall remain legally and financially responsible for performance under each of the Contracts and shall retain liability to the counterparty for any failure of Utility to perform the functions referred to in this Agreement on behalf of DWR as its limited agent, under such Contracts in accordance with the terms thereof. It is the intent of DWR and Utility that the provisions of this Agreement shall not constitute or result in an "assignment" of the Allocated Contracts in any respect.

ARTICLE IV
LIMITED DUTIES OF UTILITY

Section 4.01. Limited Duties of Utility as to the Contracts. During the Term of this Agreement, Utility shall:

(a) On behalf of DWR, as its limited agent, perform the day-to-day scheduling and dispatch functions, including day-ahead, hour-ahead and real time trading, scheduling transactions with all involved parties, under the Allocated Contracts, perform billing and settlements functions and obtain relevant information for these functions such as transmission availability and others, with respect to the Allocated Contracts set forth in Schedule 1 hereto, all as more specifically provided in the Operating Protocols attached hereto as Exhibit A;

(b) On behalf of DWR, as its limited agent, enter into transactions for the purchase (or sale, as the case may be) of gas, gas transmission services, gas storage services and financial hedges, and perform the operational and administrative responsibilities for such purchases under gas tolling provisions under the Allocated Contracts, including the review of fuel plans and consideration of alternative fuel supply, all as more specifically provided in the Fuel Management Protocols attached hereto as Exhibit B;

(c) On behalf of DWR, as its limited agent, perform all necessary billing and settlement functions under the Allocated Contracts, in accordance with the terms of the applicable Contracts. In addition, perform all necessary billing and settlement functions related to DWR Revenues and remit DWR Revenues to DWR, consistent with the Settlement Principles for Remittances and Surplus Revenues attached hereto as Exhibit C and the Servicing Arrangement;

(d) Assume financial responsibility for the ISO charges listed on Exhibit D attached hereto;

(e) On behalf of DWR, as its limited agent, upon development of a mutually agreeable plan, monitor the performance of Suppliers under the Allocated Contracts and undertake the administration of the Allocated Contracts, as more specifically provided in the Contract Administration and Performance Monitoring Protocols attached hereto as Exhibit E;

(f) Provide to DWR the necessary information required by DWR as more specifically provided in the DWR Data Requirements From Utility attached hereto as Exhibit F to facilitate DWR's continued performance of financial obligations related to Allocated Contracts and to facilitate DWR's verification, audit and monitoring related to the Allocated Contracts and reporting requirements set forth in Applicable Laws or agreements;

(g) At all times in performing its obligations under this Agreement (i) comply with the provisions of each of the Allocated Contracts, (ii) follow Good Utility Practice, and (iii) comply with all Applicable Laws and Applicable Commission Orders;

(h) Appoint a primary and secondary contact person, as set forth in Schedule 2 hereto, to coordinate the responsibilities listed in this Section 4.01; and

(i) On behalf of DWR, as its limited agent, make surplus energy sales as more specifically provided in this Agreement.
Provided, however, in the event that DWR fails to provide or provides inaccurate information which results in Utility's non-compliance with its obligations under this Agreement, the resulting non-compliance by Utility shall not constitute an Event of Default under Section 7.01 hereof.

Section 4.02. Dispatch or Sale of Allocated Power. Subject to any existing or new ISO tariff provisions that may affect the dispatch of such Contracts, Allocated Power from all Contracts shall be dispatched or sold, as the case may be, by Utility pursuant to the Operating Protocols attached hereto as Exhibit A.

Section 4.03. DWR Revenues. DWR Revenues shall be accounted and remitted to DWR consistent with the principles provided in the Settlement Principles for Remittances and Surplus Revenues attached hereto as Exhibit C and the provisions of the Servicing Arrangement. Unless otherwise specifically provided in this Agreement, Utility will not be required at any time to advance or pay any of its own funds in the fulfillment of its responsibilities under this Agreement.

Section 4.04. Ownership of Allocated Power. Notwithstanding any other provision herein, and in accordance with the Act and Section 80110 of the California Water Code, Utility and DWR agree that DWR shall retain title to all Allocated Power, including DWR Power. In accordance with the Act and Section 80104 of the California Water Code, upon the delivery of Allocated Power to Utility's customers, those customers shall be deemed to have purchased that power from DWR, and payment for such sale shall be a direct obligation of such customer to DWR. In addition, Utility and DWR agree that DWR shall retain title to any surplus Allocated Power sold by Utility as limited agent to DWR as provided in this Agreement.

ARTICLE V
DUTIES OF DWR

Section 5.01. Duties of DWR. Consistent with the Contract Allocation Order, during the Term of this Agreement, DWR shall:

(a) Remain legally and financially responsible under each of the Contracts and cooperate with Utility in the transition from DWR to Utility the performance of the functions provided in this Agreement;

(b) Assume legal and financial responsibilities and enter into or facilitate Utility's entering into transactions as DWR's limited agent, for the purchase (or sale, as the case may be) of gas, gas transmission services, gas storage services and financial hedges, and timely consent to or approve the Utility's performance of the operational and administrative responsibilities for such purchases under gas tolling provisions under the Allocated Contracts, including the review of fuel plans and consideration of alternative fuel supply, all as more specifically provided in the Fuel Management Protocols attached hereto as Exhibit B;

(c) Pay invoices to the Suppliers and perform all necessary verification, audit and monitoring of the billing and settlement functions to be performed on DWR's behalf, as its limited agent, by Utility relating to the Contracts. In addition, perform all necessary verification, audit and monitoring of the billing and settlement functions to be performed on DWR's behalf, as its limited agent, by Utility related to DWR Revenues, consistent with the principles set forth in the Settlement Principles for Remittances and Surplus Revenues attached hereto as Exhibit C;

(d) Until such time as a mutually agreed upon plan may be entered into with Utility and approved by the Commission, and no earlier than January 1, 2004, continue to monitor the performance of Suppliers and conduct certain contract administration duties under the Allocated Contracts, all as more specifically provided in the Contract Administration and Performance Monitoring Protocols attached hereto as Exhibit E. In addition, continue to perform all other administrative functions related to Contracts not explicitly provided in this Agreement to be performed by Utility on behalf of DWR, as its limited agent;

(e) Upon the termination of any Contract, submit in writing to Utility appropriate Schedules and Attachments to Exhibit A amended to reflect the termination of any Contract. Such amended Schedules and Attachments shall become effective only upon the effective date of the termination of such Contract. Provided, however, rights or obligations of the Parties that arise or relate to Utility's performance of its duties under this Agreement in respect of any terminated Contract shall survive until the expiration of any such right or obligation; and

(f) Appoint a primary and secondary contact person, as set forth in Schedule 2 hereto, to coordinate the responsibilities listed in this Section 5.01.

ARTICLE VI
[RESERVED]

Section 6.01. [Intentionally left blank.]

ARTICLE VII`
EVENTS OF DEFAULT

Section 7.01. Events of Default. The following events shall constitute "Events of Default" under this Agreement:

(a) any material failure by a Party to pay any amount due and payable under this Agreement that continues unremedied for five (5) Business Days after the earlier of the day the defaulting Party receives written notice thereof from the non-defaulting Party; or

(b) any material failure by Utility to schedule and dispatch Contracts, consistent with the principles set forth in Exhibit A; or

(c) any failure (except as provided in (a) or (b)) by a Party to duly observe or perform in any material respect any other covenant or agreement of such Party set forth in this Agreement, which failure continues unremedied for a period of 15 calendar days after written notice of such failure has been given to such Party by the non-defaulting Party; or

(d) any material representation or warranty made by a Party shall prove to be false, misleading or incorrect in any material respect as of the date made; or

(e) an Event of Default (as defined under the Servicing Arrangement) shall have occurred and is continuing under the Servicing Arrangement.

Section 7.02. Consequences of Utility Event of Default. Upon any Event of Default by Utility, DWR may, in addition to exercising any other remedies available under this Agreement or under Applicable Law, (i) terminate this Agreement in whole or in part; and (ii) apply in an appropriate forum for sequestration and payment to DWR or its Assign(s) of DWR Revenues or for specific performance of the functions related to the Contracts to be performed by Utility on behalf of DWR, as its limited agent, as provided in this Agreement.

Section 7.03. Consequences of DWR Event of Default. Upon an Event of Default by DWR (other than an Event of Default under 7.01(a)), Utility shall request that the Commission terminate this Agreement in whole or in part, Section 2.05 notwithstanding.

Section 7.04. Remedies. Subject to Article XIII of this Agreement, upon any Event of Default, the non-defaulting Party may exercise any other legal or equitable right or remedy that may be available to it under applicable law or under this Agreement.

Section 7.05. Remedies Cumulative. Except as otherwise provided in this Agreement, all rights of termination, cancellation, or other remedies in this Agreement are cumulative. Use of any remedy shall not preclude any other remedy available under this Agreement.

Section 7.06. Waivers. None of the provisions of this Agreement shall be considered waived by either Party unless the Party against whom such waiver is claimed gives such waiver in writing. The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect. Waiver by either Party of any default by the other Party shall not be deemed a waiver of any other default.

ARTICLE VIII
PAYMENT OF FEES AND CHARGES

Section 8.01. Utility Fees and Charges. As noted in the Contract Allocation Order, the details of the amount and recovery of administrative costs to Utility associated with the Contracts are expected to be considered in another Commission proceeding. As such, the Parties agree that the administrative costs to Utility will be recovered pursuant to such Commission proceeding. Utility shall enter the cost of such fees and charges in its Purchased Electric Commodity Account, or its successor or another account designated by the Commission on a current basis, for recovery in retail rates subject to subsequent Commission review.

ARTICLE IX
REPRESENTATIONS AND WARRANTIES

Section 9.01. Representations and Warranties.
(a) Each person executing this Agreement for the respective Parties expressly represents and warrants that he or she has authority to bind the Party on whose behalf he or she has executed this Agreement.

(b) Each Party represents and warrants that it has the full power and authority to execute and deliver this Agreement and to perform its terms, that execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party, and that this Agreement constitutes such Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

(c) DWR represents and warrants that all necessary and appropriate notices, inducements, undertakings, approvals, and consents have been obtained from each Supplier to the Contract allocated to Utility in order for Utility to undertake its duties set forth in this Agreement in a timely and appropriate fashion.

ARTICLE X
LIMITATIONS ON LIABILITY

Section 10.01. Consequential Damages. In no event will either Party be liable to the other Party for any indirect, special, exemplary, incidental, punitive, or consequential damages under any theory. Nothing in this Section 10.01 shall limit either Party's rights as provided in Article VII above.

Section 10.02. Limited Obligations of DWR. Any amounts payable by DWR under this Agreement shall be payable solely from moneys on deposit in the Department of Water Resources Electric Power Fund established pursuant to Section 80200 of the California Water Code (the "Fund").

Section 10.03. Sources of Payment; No Debt of State. DWR's obligation to make payments hereunder shall be limited solely to the Fund and shall be payable as an operating expense of the Fund solely from Power Charges subject and subordinate to each Priority Long Term Power Contract in accordance with the priorities and limitations established with respect to the Fund's operating expenses in any indenture providing for the issuance of Bonds and in the Rate Agreement and in the Priority Long Term Power Contracts. Any liability of DWR arising in connection with this Agreement or any claim based thereon or with respect thereto, including, but not limited to, any payment arising as the result of any breach or Event of Default under this Agreement, and any other payment obligation or liability of or judgment against DWR hereunder, shall be satisfied solely from the Fund. NEITHER THE FULL FAITH AND CREDIT NOR THE TAXING POWER OF THE STATE OF CALIFORNIA ARE OR MAY BE PLEDGED FOR ANY PAYMENT UNDER THIS AGREEMENT. Revenues and assets of the State Water Resources Development System, and Bond Charges under the Rate Agreement, shall not be liable for or available to make any payments or satisfy any obligation arising under this Agreement. If moneys on deposit in the Fund are insufficient to pay all amounts payable by DWR under this Agreement, or if DWR has reason to believe such funds may become insufficient to pay all amounts payable by DWR under this Agreement, DWR shall diligently pursue an increase to its revenue requirements as permitted under the Act from the appropriate Governmental Authority as soon as practicable. To the extent DWR's obligations are "administrative costs," they will require annual appropriation by the legislature.

Section 10.04. Cap on Liability. In no event will Utility be liable to DWR for damages under this Agreement, including indemnification obligations, whether in contract, warranty, tort (including negligence), strict liability or otherwise (referred to as "Damages" for purposes of this Section), in an amount in excess of: 1) on an annual calendar year basis, $5 million plus ten percent of Damages in excess of $5 million and 2) for the entire term of this Agreement, $50 million in total payments of Damages to DWR. For example, if Damages for an event are $100 million, Utility's total liability for this event would be $14.5 million ($5 million plus10% of $95 million) and that would be the full extent of Utility's liability for such Damages. All Damages associated with an event will apply only to the annual limit in the first year in which Damages for that event were assessed. For example, if Damages for an event were paid as follows: $15 million in year 1 and $10 million in year 2, the Utility would pay DWR $7 million ($5 million plus10% of $10 million for year 1 and 10% of $10 million for year 2). In this example, the $1 million paid to DWR in year 2 (10% of $10 million) does not count against the year 2 $5 million calendar year threshold. DWR hereby releases Utility from any liability for Damages in excess of the limitations on liability set forth in this Section 10.04, provided however, that this limitation on Utility liability shall not apply to the extent the liability is a result of Utility's gross negligence or willful misconduct.

ARTICLE XI
CONFIDENTIALITY

Section 11.01. Proprietary Information.
(a) Nothing in this Agreement shall affect Utility's obligations to observe any Applicable Law prohibiting the disclosure of Confidential Information regarding its customers.

(b) Nothing in this Agreement, and in particular nothing in Sections 11.01(e)(x) through 11.01(e)(z) of this Agreement, shall affect the rights of the Commission to obtain from Utility, pursuant to Applicable Law, information requested by the Commission, including Confidential Information provided by DWR to Utility. Applicable Law, and not this Agreement, will govern what information the Commission may disclose to third parties, subject to any confidentiality agreement between DWR and the Commission.

(c) The Parties acknowledge that each Party may acquire information and material that is the other Party's confidential, proprietary or trade secret information. As used herein, "Confidential Information" means any and all technical, commercial, financial and customer information disclosed by one Party to the other (or obtained from one Party's inspection of the other Party's records or documents), including any patents, patent applications, copyrights, trade secrets and proprietary information, techniques, sketches, drawings, maps, reports, specifications, designs, records, data, models, inventions, know-how, processes, apparati, equipment, algorithms, software programs, software source documents, object code, source code, and information related to the current, future and proposed products and services of each of the Parties, and includes, without limitation, the Parties' respective information concerning research, experimental work, development, design details and specifications, engineering, financial information, procurement requirements, purchasing, manufacturing, business forecasts, sales and merchandising, and marketing plans and information. In all cases, Confidential Information includes proprietary or confidential information of any third party disclosing such information to either Party in the course of such third party's business or relationship with such Party. Utility's Confidential Information also includes any and all lists of customers, and any and all information about customers, both individually and aggregated, including but not limited to customers' names, street addresses of customer residences and/or facilities, email addresses, identification numbers, Utility account numbers and passwords, payment histories, energy usage, rate schedule history, allocation of energy uses among customer residences and/or facilities, and usage of DWR Power. All Confidential Information disclosed by the disclosing Party ("Discloser") will be considered Confidential Information by the receiving Party ("Recipient") if identified as confidential and received from Discloser.

(d) Each Party agrees to take all steps reasonably necessary to hold in trust and confidence the other Party's Confidential Information. Without limiting the generality of the immediately preceding sentence, each Party agrees (i) to hold the other Party's Confidential Information in strict confidence, not to disclose it to third parties or to use it in any way, commercially or otherwise, other than as permitted under this Agreement; and (ii) to limit the disclosure of the Confidential Information to those of its employees, agents or directly related subcontractors with a need to know who have been advised of the confidential nature thereof and who have acknowledged their express obligation to maintain such confidentiality. DWR shall not disclose Confidential Information to employees, agents or subcontractors that are in any respect responsible for power marketing or trading activities associated with the State Water Resources Development System.

(e) The foregoing two paragraphs will not apply to any item of Confidential Information if: (i) it has been published or is otherwise readily available to the public other than by a breach of this Agreement; (ii) it has been rightfully received by Recipient from a third party without breach of confidentiality obligations of such third party and outside the context of the provision of services under this Agreement; (iii) it has been independently developed by Recipient personnel having no access to the Confidential Information; (iv) it was known to Recipient prior to its first receipt from Discloser, or (v) it has been summarized, processed and incorporated for incorporation into reports, discussions, statements or any other further work product. In addition, Recipient may disclose Confidential Information if and to the extent required by law or a Governmental Authority, provided that (x) Recipient shall give

Discloser a reasonable opportunity to review and object to the disclosure of such Confidential Information, (y) Discloser may seek a protective order or confidential treatment of such Confidential Information, and (z) Recipient shall make commercially reasonable efforts to cooperate with Discloser in seeking such protective order or confidential treatment. Discloser shall pay Recipient its reasonable costs of cooperating.

Section 11.02. No License. Nothing contained in this Agreement shall be construed as granting to a Party a license, either express or implied, under any patent, copyright, trademark, service mark, trade dress or other intellectual property right, or to any Confidential Information now or hereafter owned, obtained, controlled by, or which is or may be licensable by, the other Party.

Section 11.03. Survival of Provisions. The provisions of this Article XI shall survive the termination of this Agreement.

ARTICLE XII
RECORDS AND AUDIT RIGHTS

Section 12.01. Records. Utility shall maintain accurate records and accounts relating to the Contracts in sufficient detail to permit DWR to audit and monitor the functions to be performed by Utility on behalf of DWR, as its limited agent, under this Agreement. In addition, Utility shall maintain accurate records and accounts relating to DWR Revenues to be remitted by Utility to DWR, consistent with the Settlement Principles for Remittances and Surplus Revenues set forth in Exhibit C hereto. Utility shall provide to DWR and its Assign(s) access to such records. Access shall be afforded without charge, upon reasonable request made pursuant to Section 12.02. Access shall be afforded only during Business Hours and in such a manner so as not to interfere unreasonably with Utility's normal operations. Utility shall not treat DWR Revenues as income or assets of Utility or any affiliate for any tax, financial reporting or regulatory purposes, and the financial books or records of Utility and affiliates shall be maintained in a manner consistent with the absolute ownership of DWR Revenues by DWR and Utility's holding of DWR Revenues in trust for DWR (whether or not held together with other monies).

Section 12.02. Audit Rights.
(a) Upon 30 calendar days' prior written notice, DWR may request an audit, conducted by DWR or its agents (at DWR's expense), of Utility's records and procedures, which shall be limited to records and procedures containing information bearing upon Utility's performance of its obligations under this Agreement. The audit shall be conducted during Business Hours without interference with Utility's normal operations, and in compliance with Utility's security procedures.

(b) As provided in the Act, the State of California Bureau of State Audits (the "Bureau") shall conduct a financial and performance audit of DWR's implementation of Division 27 (commencing with Section 80000) of the California Water Code, and the Bureau shall issue a final report on or before March 31, 2003. In addition, as provided in Section 8546.7 of the California Government Code, Utility agrees that, pursuant to this Section 12.02, DWR or the State of California Department of General Services, the Bureau, or their designated representative ("DWR's Agent") shall have the right to review and to copy (at DWR's expense) any non-confidential records and supporting documentation pertaining to the performance of this Agreement and to conduct an on-site review of any Confidential Information pursuant to Section 12.03 hereof. Utility agrees to maintain such records for such possible audit for three years after final Remittance to DWR. Utility agrees to allow such auditor(s) access to such records during Business Hours and to allow interviews of any employees who might reasonably have information related to such records. Further, Utility agrees to include a similar right for DWR or DWR's Agent to audit records and interview staff in any contract between Utility and a subcontractor directly related to performance of this Agreement.

Section 12.03. Confidentiality. Materials reviewed by either Party or its agents in the course of an audit may contain Confidential Information subject to Article XI above. The use of all materials provided to DWR or Utility or their agents, as the case may be pursuant to this Article XII, shall comply with the provisions in Article XI and shall be limited to use in conjunction with the conduct of the audit and preparation of a report for appropriate distribution of the results of the audit consistent with Applicable Law.

Section 12.04. Annual Certifications. At least annually, and in no event later than the tenth Business Day after the end of the calendar year, Utility shall deliver to DWR a certificate of an authorized representative certifying that to the best of such representative's knowledge, after a review of Utility performance under this Agreement, Utility has fulfilled its obligations under this Agreement in all material respects and is in compliance herewith in all material respects.

Section 12.05. Additional Applicable Laws. Each Party shall make an effort to promptly notify the other Party in writing to the extent such Party becomes aware of any new Applicable Laws or changes (or proposed changes) in Applicable Tariffs hereafter enacted, adopted or promulgated that may have a material adverse effect on either Party's ability to perform its duties under this Agreement. A Party's failure to so notify the other Party pursuant to this Section 12.05 will not constitute a material breach of this Agreement, and will not give rise to any right to terminate this Agreement or cause either Party to incur any liability to the other Party or any third party.

Section 12.06. Other Information. Upon the reasonable request of DWR or its Assign(s), Utility shall provide to DWR or its Assign(s) any public financial information in respect of Utility applicable to services provided by Utility under this Agreement, to the extent such information is reasonably available to Utility, which (i) is reasonably necessary and permitted by Applicable Law to monitor the performance by Utility hereunder, or (ii) otherwise relates to the exercise of DWR's rights or the discharge of DWR's duties under this Agreement or any Applicable Law. In particular, but without limiting the foregoing, Utility shall provide to DWR any such information that is necessary or useful to calculate DWR's revenue requirements (as described in Sections 80110 and 80134 of the California Water Code).

Section 12.07. Data and Information Retention. All data and information associated with the provision and receipt of services pursuant to this Agreement shall be maintained for the greater of (a) the retention time required by Applicable Law or Applicable Tariffs for maintaining such information, or (b) three (3) years.

ARTICLE XIII
DISPUTE RESOLUTION

Section 13.01. Dispute Resolution. Should any dispute arise between the Parties or should any dispute between the Parties arise from the exercise of either Party's audit rights contained in Section 12.02 hereof, the Parties shall remit any undisputed amounts and agree to enter into good faith negotiations as soon as practicable to resolve such disputes within (10) Business Days so as to resolve such disputes, as appropriate, within the timeframes provided under this Agreement, or as soon as possible thereafter. For any disputed Remittances, if such resolution cannot be made before the remittance date, Utility shall remit the undisputed portion to DWR. In addition, the disputed portion of the Remittances shall be deposited into an escrow account held by a qualified, independent escrow holder. Upon resolution of such disputes, the Party that escrowed the disputed amount shall reimburse the other Party from the escrow account as necessary.

Section 13.02. ISO Settlements Disputes. Utility shall review, validate and verify all ISO charges/credits contained on all ISO settlement statements, including any charges/credits resulting from functions related to the Contracts to be performed by Utility as provided in this Agreement. Utility shall inform DWR of any discrepancies and shall dispute any such discrepancies with the ISO in accordance with the ISO's tariff and protocols. Except as provided in Section 13.03, if any ISO charge type settlement amount appearing on a Preliminary or Final Settlement Statement (as defined in the ISO tariff) resulting or relating to the Utility's performance of functions related to the Contracts under this Agreement is in dispute, it shall be the responsibility of Utility, on behalf of DWR, as its limited agent, to seek resolution of said dispute through the ISO dispute resolution process as provided in the ISO's tariff.

For disputes affecting Utility's Remittances to DWR, including disputes on ISO charges to non-DWR parties that would affect Remittances to DWR, Utility shall provide to DWR: a) notification of submission of the dispute through the ISO dispute resolution process, identifying, among other items, the dispute type, quantity, price and allocation; b) a copy of the submitted dispute and all supporting data; and c) a copy of all ensuing documentation resulting from the ongoing dispute resolution process. Utility shall track and validate all disputed ISO charges involving any financial responsibility of DWR.

Section 13.03. Supplier Invoice Disputes. DWR shall continue to be responsible for all dispute resolution relating to Supplier invoices. In addition, except as specifically provided in Exhibit E of this Agreement, all other contract administration functions shall remain DWR's responsibility.

Section 13.04. Good-Faith Negotiations. Should any dispute arise between the Parties relating to this Agreement, the Parties shall undertake good-faith negotiations to resolve such dispute. If the Parties are unable to resolve such dispute through good-faith negotiations, either Party may submit a detailed written summary of the dispute to the other Party. Upon such written presentation, each Party shall designate an executive with authority to resolve the matter in dispute. If the Parties are unable to resolve such dispute within 30 days from the date that a detailed summary of such dispute is presented in writing to the other Party, then either Party may, at its sole discretion, submit the dispute to the Commission for resolution, in accordance with Applicable Law. Nothing herein shall preclude either Party from challenging the decision or action which such Party deems may adversely affect its interests in any appropriate forum of the Party's choosing.

Section 13.05. Costs. Each Party shall bear its own respective costs and attorney fees in connection with respect to any dispute resolution process undertaken by it pursuant to this Article. Provided, however, DWR shall reimburse Utility all reasonably incurred costs, including, but not limited to, in-house and retained attorneys, consultants, witnesses, and arbitration costs, arising from or pertaining to all disputes relating to ISO charges/credits contained on all ISO settlement statements resulting from the operational, dispatch and administrative functions related to the Contracts performed by Utility on behalf of DWR, as its limited agent, pursuant to the standards set forth in Section 2.02 herein and consistent with the provisions of the ISO tariff, as may be amended from time to time, including disputes on ISO charges to non-DWR parties that would affect Remittances to DWR. These costs shall be recorded and invoiced in the manner set forth in Section 8.01 hereof.

ARTICLE XIV
MISCELLANEOUS

Section 14.01. Assignment
(a) Except as provided in paragraphs (b) and (c) below, neither Party shall assign or otherwise dispose of this Agreement, its right, title or interest herein or any part hereof to any part hereof to any entity, without the prior written consent of the other Party. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee. When duly assigned in accordance with this Section 14.01(a) and when accepted by the assignee, this Agreement shall be binding upon and shall inure to the benefit of the assignee. Any assignment in violation of this Section 14.01(a) shall be void.

(b) Utility acknowledges and agrees that DWR may assign or pledge its rights to receive performance hereunder to a trustee or another party ("Assign(s)") in order to secure DWR's obligations under its bonds (as that term is defined in the Act), and any such Assign shall be a third party beneficiary of this Agreement; provided, however, that this authority to assign or pledge rights to receive performance hereunder shall in no event extend to any person or entity that sells power or other goods or services to DWR.

(c) Any person (i) into which Utility may be merged or consolidated, (ii) which may result from any merger or consolidation to which Utility shall be a party or (iii) which may succeed to the properties and assets of Utility substantially as a whole, which person in any of the foregoing cases executes an agreement of assumption to perform every obligation of Utility hereunder, shall be the successor to Utility under this Agreement without further act on the part of any of the Parties to this Agreement; provided, however, that Utility shall have delivered to DWR and DWR its Assign(s) an opinion of counsel reasonably acceptable to DWR stating that such consolidation, merger or succession and such agreement of assumption complies with this Section 13.01(c) and that all of Utility's obligations hereunder have been validly assumed and are binding on any such successor or assign.

(d) Notwithstanding anything to the contrary herein, DWR's rights and obligations hereunder shall be transferred, without any action or consent of either Party hereto, to any entity created by the State legislature which is required under Applicable Law to assume the rights and obligations of DWR under Division 27 of the California Water Code.

Section 14.02. Force Majeure. Neither Party shall be liable for any delay or failure in performance of any part of this Agreement (including the obligation to remit money at the times specified herein) from any cause beyond its reasonable control, including but not limited to, unusually severe weather, flood, fire, lightning, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or Government Authority, or any combination of these causes, which by the exercise of due diligence and foresight such Party could not reasonably have been expected to avoid and which by the exercise of due diligence is unable to overcome.

Section 14.03. Severability. In the event that any one or more of the provisions of this Agreement shall for any reason be held to be unenforceable in any respect under applicable law, such unenforceability shall not affect any other provision of this Agreement, but this Agreement shall be construed as if such unenforceable provision or provisions had never been contained herein.

Section 14.04. Survival of Payment Obligations. Upon termination of this Agreement, each Party shall remain liable to the other Party for all amounts owing under this Agreement. Utility shall continue to collect and remit, pursuant to the terms of the Servicing Arrangement and the principles provided in the Settlement Principles for Remittances and Surplus Revenues provided in Exhibit C hereto and any DWR Charges billed to customers or any DWR Surplus Energy Sales Revenues attributable to sales entered into before the effective date of termination of the Servicing Arrangement.

Section 14.05. Third-Party Beneficiaries. The provisions of this Agreement are exclusively for the benefit of the Parties and any permitted assignee of either Party and there are no third party beneficiaries under this Agreement.

Section 14.06. Governing Law. This Agreement shall be interpreted, governed and construed under the laws of the State of California without regard to choice of law provisions.

Section 14.07. Multiple Counterparts. This Agreement may be executed in multiple counterparts, each of which shall be an original.

Section 14.08. Section Headings. Section and paragraph headings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of text.

Section 14.09. Amendments. No amendment, modification, or supplement to this Agreement shall be effective unless it is in writing and signed by the authorized representatives of both Parties and approved as required, and by reference incorporates this Agreement and identifies the specific portions that are amended, modified, or supplemented or indicates that the material is new. No oral understanding or agreement not incorporated in this Agreement is binding on either of the Parties.

Section 14.10. Amendment Upon Changed Circumstances. The Parties acknowledge that compliance with any Commission decision, legislative action or other governmental action (whether issued before or after the Effective Date of this Agreement) affecting the operation of this Agreement, including but not limited to (i) dissolution of the ISO, (ii) changes in the ISO market structure, (iii) a decision regarding direct access currently pending before the Commission, (iv) the establishment of other Governmental Programs, or (v) a modification to the Contract Allocation Agreement may require that amendment(s) be made to this Agreement. The Parties therefore agree that if either Party reasonably determines that such a decision or action would materially affect the services to be provided hereunder or the reasonable costs thereof, then upon the issuance of such decision or the approval of such action (unless and until it is stayed), the Parties will negotiate the amendment(s) to this Agreement that is (or are) appropriate in order to effectuate the required changes in services to be provided or the reimbursement thereof. If the Parties are unable to reach agreement on such amendments within 60 days after the issuance of such decision or approval of such action, either Party may, in the exercise of its sole discretion, submit the disagreement to the Commission for proposed resolution. Nothing herein shall preclude either Party from challenging the decision or action which such Party deems may adversely affect its interests in any appropriate forum of the Party's choosing.

The Parties agree that, if the rating agencies request changes to this Agreement which the Parties reasonably determine are necessary and appropriate, the Parties will negotiate in good faith, but will be under no obligation to reach agreement or to ask the Commission to amend this Agreement to accommodate the rating agency requests and will cooperate in obtaining any required approvals of the Commission or other entities for such amendments.

Section 14.11 Indemnification.

(a) Indemnification of DWR. Utility (the "Indemnitor") shall at all times protect, indemnify, defend and hold harmless DWR, and its elected officials, appointed officers, employees, representatives, agents and contractors (each, an "Indemnified Party" or an "Indemnitee") from and against (and pay the full amount of) any and all claims (whether in tort, contract or otherwise), demands, expenses (including, without limitation, in-house and retained attorneys' fees) and liabilities for losses, damage, injury and liability of every kind and nature and however caused, and taxes (of any kind and by whomsoever imposed), to third parties arising from or in connection with (or alleged to arise from in connection with): (1) any failure by Utility to perform its material obligations under this Agreement; (2) any material representation or warranty made by Utility shall prove to be false, misleading or incorrect in any material respect as of the date made; (3) the gross negligence or willful misconduct of Utility or any of its officers, directors, employees, agents, 0representatives, subcontractors or assignees in connection with this Agreement; and (4) any violation of or failure by Utility or Indemnitor to comply with any Applicable Commission Orders or Applicable Law; provided, however, that the foregoing indemnifications and protections shall not extend to any losses arising from gross negligence or willful misconduct of any Indemnified Party.

(b) Obligation of Utility. Consistent with the Contract Allocation Order, Utility shall not, in acting as limited agent of DWR hereunder be required to perform any obligations of any Supplier under any Allocated Contract or to make any payments on behalf of such Supplier or as the result of the failure of such Supplier to perform under any Allocated Contract.

(c) Indemnification of Utility. To the extent permitted by law, DWR ("Indemnitor") shall at all times protect, indemnify, defend and hold harmless Utility, and its officers, employees, representatives, agents and contractors (each, an "Indemnified

Party" or "Indemnitee"), from and against (and pay the full amount of) any and all claims (whether in tort, contract or otherwise), demands, expenses (including, without limitation, in-house and retained attorneys' fees) and liabilities for losses, damage, injury and liability of every kind and nature and however caused, and taxes (of any kind and by whomsoever imposed), to third parties arising from or in connection with (or alleged to arise from on in connection with): (1) any failure by DWR to perform its material obligations under this Agreement or any Allocated Contract; (2) any material representation or warranty made by DWR shall prove to be false, misleading or incorrect in any material respect as of the date made; (3) the gross negligence or willful misconduct of the DWR or any of its officers, directors or employees, agents, representatives, subcontractors or assignees in connection with this Agreement; (4) any action claiming Utility failed to perform any Supplier's obligations under an Allocated Contract; and (5) any violation of or failure by DWR or Indemnitor to comply with any Applicable Law; and provided, however, that the foregoing indemnifications and protections shall not extend to any losses arising from the gross negligence or willful misconduct of any Indemnified Party.

(d) Indemnification Procedures. Indemnitee shall promptly give notice to Indemnitor of any claim or action to which it seeks indemnification from Indemnitor. Indemnitor shall defend any such claim or action brought against it, and may also defend such claim or action on behalf of the Indemnitee (with counsel reasonably satisfactory to Indemnitor) unless there is any actual or potential conflict between Indemnitor and Indemnitee with respect to such claim or action. If there is any actual or potential conflict between Indemnitor and Indemnitee with respect to such claim or action, Indemnitee shall have the opportunity to assume (at Indemnitor's expense) defense of any claim or action brought against Indemnitee by a third party; however, failure by Indemnitee to request defense of such claim or action by the Indemnitor shall not affect Indemnitee's right to indemnity under this Section 14.11. In any action or claim involving Indemnitee, Indemnitor shall not settle or compromise any claim without the prior written consent of Indemnitee.

Section 14.12. Notices and Demands. (a) Except as otherwise provided under this Agreement, all notices, demands, or requests pertaining to this Agreement shall be in writing and shall be deemed to have been given (i) on the date delivered in person, (ii) on the date when sent by facsimile (with receipt confirmed by telephone by the intended recipient or his or her authorized representative) or electronic transmission (with receipt confirmed telephonically or electronically by the intended recipient or his or her authorized representative) or by special messenger, or (iii) 72 hours following delivery to a United States post office when sent by certified or registered United States mail postage prepaid, and addressed as set forth below:

Utility: San Diego Gas & Electric Company
8330 Century Park Court, CP32D
San Diego, California 92123

Attn: Lad Lorenz
Vice President, Electric and Gas Procurement
Telephone: (858) 650-6150
Facsimile: (858) 650-6191
Email: llorenz@SDGE.com

DWR: State of California
The Resources Agency
Department of Water Resources
California Energy Resources Scheduling Division
3310 El Camino Avenue, Suite 120
Sacramento, California 95821

Attn: Peter S. Garris
Deputy Director
Telephone: (916) 574-2733
Facsimile: (916) 574-0301
Email: pgarris@water.ca.gov

(b) Each Party shall be entitled to specify as its proper address any other address in the United States, or specify any change to the above information, upon written notice to the other Party complying with this Section 14.12.

(c) Each Party shall designate on Attachment A the person(s) to be contacted with respect to specific operational matters. Each Party shall be entitled to specify any change to such person(s) upon written notice to the other Party complying with this Section 14.12.

Section 14.13. Approval. This Agreement shall be effective upon the execution by both Parties and approval of such executed agreement by the Commission. Except as expressly provided otherwise herein, neither Party may commence performance hereunder until such date. Any delay in the commencement of performance hereunder as a consequence of waiting for such approval(s) shall not be a breach or default under this Agreement.

Section 14.14. Government Code and Public Contract Code Inapplicable. DWR has determined, pursuant to Section 80014(b) of the California Water Code, that application of certain provisions of the Government Code and Public Contract Code applicable to State contracts, including but not limited to advertising and competitive bidding requirements and prompt payment requirements, would be detrimental to accomplishing the purposes of Division 27 (commencing with Section 80000) of the California Water Code and that such provisions and requirements are therefore not applicable to or incorporated in this Agreement.

Section 14.15. Annual Review. The provisions of the Exhibits are subject to annual review by DWR and Utility to ensure their relevance and usefulness. In the event that the Parties mutually agree that certain provisions of the Exhibits should be amended or supplemented, an amendment to the Exhibit should be executed and Utility shall submit to the Commission for approval.

Section 14.16 Other Operating Agreement. It is DWR's intent to have a consistent operating agreement with all three investor-owned utilities (IOUs). Should DWR reach an operating agreement with another IOU relating to the subject matter of this Agreement, that in Utility's judgment is more favorable on the whole than this Agreement, Utility shall have the right to receive the same terms and conditions as such other IOU. This provisions specifically does not allow Utility to select particular portions or provisions of such other IOU's operating agreement. In addition, if Utility elects to be subject to such other IOU's operating agreement's terms and conditions, Utility shall be subject to such other IOU's operating agreement with only such modifications agreed to by DWR as necessary to address operating differences between that other IOU and Utility. Utility shall exercise the foregoing right within 60 days following Commission approval of such other operating agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement on the date or dates indicated below, to be effective as of the Effective Date.

CALIFORNIA STATE DEPARTMENT OF WATER RESOURCES, acting solely under the authority and powers granted by ABIX, codified as Sections 80000 through 80270 of the Water Code, and not under its powers and responsibilities with respect to the State Water Resources Development System	SAN DIEGO GAS & ELECTRIC COMPANY, a California corporation
By: ____________________________	By: ________________________________
Name: ___________________________	Name:___JAMES P. AVERY____________
Title: __________________________	Title:____SENIOR VICE PRESIDENT____
Date:___________________________	Date:_______________________________

Schedule 1

ALLOCATED CONTRACTS

Schedule 2

REPRESENTATIVES AND CONTACTS

LAD LORENZ
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SDG&E EXHIBIT A
OPERATING PROTOCOLS

EXHIBIT A

OPERATING PROTOCOLS

Pursuant to Section 4.01 of this Agreement, on behalf of DWR as its limited agent, Utility shall perform the day-to-day scheduling and dispatch functions, including day-ahead, hour-ahead and real-time trading, scheduling of transactions with all involved parties, making surplus energy sales and obtaining relevant information for these functions such as transmission availability and others, with respect to the Allocated Contracts set forth in Schedule 1 to the Agreement, all as more specifically provided below and in compliance with the provisions of each of the Contracts:

I. Resource Commitment and Dispatch. Utility agrees to use good faith efforts to dispatch Allocated Contracts, based on the principle of "least cost dispatch" to retail customers, consistent with the Contract Allocation Order and other Applicable Commission Orders. Utility shall undertake these least cost dispatch functions both of Allocated Contracts and its URG so as to minimize the cost of service to retail customers based on circumstances known or that reasonably could have been known by Utility at the time dispatch decisions are made. DWR shall have no role in enforcement or review of Utility least cost dispatch under this Agreement and all issues of Utility compliance with least cost dispatch shall be within the sole review of the Commission.

A. Annual, Quarterly and Weekly Load and Resource Assessment Studies. Utility shall provide to DWR copies of its annual and quarterly load and resource assessment studies. Provided that Utility submits substantially the same information to the Commission, copies of the Commission submission will be simultaneously sent to DWR to satisfy requirements of this section. In addition, Utility will provide a weekly commitment and dispatch plan for informational purposes to DWR in the same form that such plan is used internally.

B. Scheduling Protocols.

1. DWR is responsible for notifying the counter-party to each of the Allocated Contracts that scheduling under the Allocated Contracts will be performed by Utility before the first day that schedules are due to be submitted by Utility. DWR is responsible for notifying Utility of any changes to the Allocated Contracts that it has negotiated, including changes to the scheduling terms. DWR agrees to provide such notice as soon as possible following the negotiation of any changed provisions and in any case prior to the time that any changed provisions become effective.

2. Utility agrees to schedule Contracts in accordance with their terms and in accordance with the requirements of the Control Area operator or operators with whom the Contract must be scheduled to provide for power delivery.

II. ISO Ancillary Service (AS) Market. Among the Contracts are resources that are or may be qualified to be bid into the ISO's Ancillary Services ("AS") market or that Utility may use in its self-provision of AS. Utility is authorized to develop protocols and procedures for the use of DWR resources for AS. Utility shall, upon DWR's request, provide to DWR such information concerning Utility's intended use of DWR resources for AS as DWR may reasonably request for planning and revenue requirement purposes.

III. Surplus Energy Sales and Energy Exchanges

A. Over-generation. If the ISO announces an over-generation situation Utility will back down resources in accordance with the ISO tariff and Good Utility Practice. In order to reduce the need for physical curtailment in over-generation situations, DWR and Utility shall develop pay for curtailment protocols and procedures that will enable Utility to instruct a must-take resource not to deliver energy under specified conditions. The costs and charges associated with mitigation of an over-generation situation shall be allocated among the Parties on a pro-rata basis consistent with the surplus sales allocation principles set forth in Exhibit C.

B. Energy Exchange Arrangements. Existing non-DWR/CERS exchanges and those that might be transacted post-2002, will be considered URG exchanges. The accounting of energy necessary to support energy exchanges is addressed in Exhibit C.

C. Surplus Energy Sales Arrangement. Utility shall on a monthly basis prepare a sales plan addressing all surplus sales, including without limitation sales to manage over-generation, contemplated by the Utility for review by DWR. Such plan shall address sales of power from the combined portfolio of URG resources and Allocated Contracts, which will be administered by Utility on its own behalf and acting as DWR's limited agent. As specified in Section 2.02 of the Agreement, Utility shall pursue surplus sales in a fashion reasonably designed to serve the overall best interests of retail electric customers based on information known or could have been known by Utility at the time. Utility agrees to include sufficient details in the sales plans to allow DWR to satisfy its financial management and reporting requirements. To the extent there is surplus power uncommitted to a forward energy surplus sales transaction, Utility shall be required to bid such surplus energy in the day-ahead, hour-ahead or real-time market. Utility shall arrange for transmission service to accommodate surplus sales to the extent that transmission service is available and cost effective. The costs of transmission service, ISO charges and the costs of firm transmission rights associated with such surplus energy sales transactions shall be treated in accordance with the Settlement Principles for Remittances and Surplus Revenues attached hereto as Exhibit C.

IV. Outage Coordination and Determination of Resource Availability of Contracts. Utility shall communicate with the Scheduling Coordinator of each Contract to coordinate, approve, document and report planned Contract outages. For those Contracts where resource availability affects capacity payments, Utility will use good faith efforts to verify supplier actual resource availability, and keep records of resource availability as reported by Supplier. In addition, Utility shall document all outages (forced and planned) and notices of outages of DWR contract resources and provide such documents to DWR within five (5) business days after the end of each calendar month.

SDG&E EXHIBIT B
FUEL MANAGEMENT PROTOCOLS

EXHIBIT B

FUEL MANAGEMENT PROTOCOLS

Certain of the Contracts listed on Schedule 1 of this Agreement provide DWR the option of either (i) letting the Supplier provide the necessary natural gas for its generating units at an index-based price or agreed upon fixed price or (ii) DWR procuring the gas supply and causing such supply to be delivered to the Supplier under a tolling arrangement ("Fuel Option"). Certain of the Contracts with Fuel Option provide that DWR can decide on a monthly basis whether to procure the gas and others provide that the decision be made annually or semi-annually when DWR reviews the Supplier's proposed fuel plan.

The purpose of this Exhibit B is to describe the relationship which will exist between DWR and Utility and the specific responsibilities of each as they all relate to managing the natural gas provisions of the Contracts which include Fuel Options. Specifically, this Exhibit B will address responsibilities for the following activities: (i) determining types and lengths of gas contracts, (ii) nominating deliveries, (iii) contracting for gas transportation and storage, (iv) managing imbalances, (v) reviewing, authorizing and making payment of gas invoices and (vi) determining and implementing hedge strategies, as appropriate.

I. Operating Relationship Between DWR and Utility

While DWR will retain legal and financial responsibility for gas and related services, Utility shall, as a limited agent acting for DWR, perform the administrative and operational activities, as further specified below, required to ensure adequate gas is supplied to Suppliers' generating units, consistent with the tolling provisions included in the Contracts. The intent of this relationship is to provide Utility sufficient flexibility and authority to execute normal day-to-day activities associated with managing the fuel provisions of tolling Contracts and procurement of natural gas and related services, as a limited agent acting on behalf of DWR without direct involvement by DWR but in a manner consistent with Utility Gas Supply Plans which have been reviewed and approved by DWR and the Commission.

II. Fuel Activities

Consistent with the terms of the Contracts with Fuel Options, Utility shall have administrative and operational authority to act, as a limited agent, for fuel supply related activities, consistent with the following goals and guidelines whenever Utility has recommended, and DWR has reviewed and approved such recommendation that gas for a Contract with Fuel Option be caused to be supplied by Utility from a list of approved providers.

1. Utility shall use reasonable commercial efforts to secure delivery of gas in a reliable manner and consistent with gas requirements for producing scheduled energy.

2. Utility shall develop a portfolio of gas supply for the Contracts that contain Fuel Options and where Utility is to supply gas, acting as limited agent on behalf of DWR, consistent with the approved Utility Gas Supply Plans. Such portfolio should be diversified in terms of price mechanism, period of performance, and gas suppliers.

3. Utility shall develop a portfolio of supply, which is reasonably priced relative to the market and in accordance with an approved Utility Gas Supply Plan.

III. Review of Supplier Fuel Plans

In accordance with the terms of each of the Contracts with Fuel Options, Utility, acting as a limited agent on behalf of DWR, shall review each fuel plan prepared and submitted by the Supplier, and forwarded to the Utility by DWR, and determine whether to recommend (i) approval of the Supplier Fuel Plan and authorization for the Supplier to provide gas to its generating unit(s), or (ii) procurement and management of gas supplies to the generating unit(s) by Utility. Utility, acting as a limited agent on behalf of DWR, shall advise DWR and the Commission on a timely basis of its recommendation regarding responsibility for supplying natural gas. DWR shall, on a timely basis, review Utility's recommendation and either approve or identify requested changes. Once approved, Utility shall advise the Supplier in accordance with the time requirements included in the appropriate Contract with Fuel Option. In addition, for any Supplier Fuel Plans which have been implemented and are operative as of the Effective Date, and where DWR has previously elected to be responsible for gas supply, Utility may advise DWR that it would rather have Supplier provide the gas as of the Effective Date. DWR shall coordinate with Utility and Supplier to revise such Supplier Fuel Plans, to the extent possible, prior to the Effective Date.

IV. Fuel Procurement Strategies

Under the Contracts with Fuel Option, upon Utility's recommendation, and DWR's review and approval of such recommendation, Utility will be responsible for procuring the natural gas fuel from a list of approved gas providers. Utility shall, acting as the limited agent of DWR, have administrative and operational responsibility for determining its gas procurement strategies, including but not limited to (i) types of contracts, (ii) length of contracts, (iii) pricing terms, (iv) use of storage, (v) types of gas transportation, (vi) delivery point(s), (vii) whether and how to obtain gas price forecasts, (viii) if and what risk management tools are to be used, and (ix) how to maintain current market intelligence.

Utility shall consolidate these strategies and submit them to DWR and the Commission as a "Utility Gas Supply Plan" by April 17, 2003 and, thereafter on a semi-annual basis during the Term. Utility may also provide a copy of such Gas Supply Plan to DWR in advance of the filing with the Commission so as to be able to indicate DWR's approval of such plan. Utility shall indicate in its Advice letter filing to the Commission whether DWR has approved such plan as appropriate. DWR shall also formally notify the Commission when it has approved such plan.

DWR and the Commission will review and approve the Utility Gas Supply Plans. In the event of conflicting guidance between the Commission and DWR regarding various aspects of the Gas Supply Plan they respectively approve or reject, where DWR only approves a subset of what the Commission approves, then Utility shall operate within the sphere of DWR's approval. If, however, the Commission explicitly rejects portions of the Gas Supply Plan that DWR would authorize, then Utility must operate within the limitations of the Commission's decision. After a reasonable period of time operating within the framework of the Gas Supply Plans and the Commission's and DWR's respective approval and/or rejection of various pieces of the Gas Supply Plan, the Parties agree to meet and confer to determine whether the approval process may need to be revised in some manner, and Utility shall submit to Commission any such proposed revisions. Once approved, Utility may act within such Utility Gas Supply Plan without further DWR involvement, except as provided below.

V. Gas Purchasing

Utility and DWR shall jointly determine a list of approved gas providers who can be used to supply gas under the Contracts with Fuel Options. Master agreements intended to cover normal day-to-day volumes will then be executed with such approved providers. While DWR will be the executing party under all DWR gas contracts, such agreements shall specifically authorize Utility to act for and on behalf of DWR, as a limited agent, in negotiating specific prices, quantities and delivery periods for specific purchases under such master agreements; provided however, on the earliest practicable date after the execution of this Agreement, DWR agrees to provide to Utility in writing and in advance of such negotiations any limits, including without limitation any terms, that may be required by DWR. If Utility determines it would be beneficial to enter into any DWR gas contract which exceeds 3 months or have a total value exceeding $10 million, it shall negotiate such agreement(s) and submit them to DWR for advance approval and execution.

VI. Gas Transportation

Utility shall have responsibility for recommending to DWR which pipelines should transport gas if Utility, acting as limited agent on behalf of DWR is to supply gas under a Contract with Fuel Option. Following approval of or revision of Utility Gas Supply Plan, Utility shall negotiate firm and/or interruptible agreements with such pipelines, consistent with the Utility Gas Supply Plan and submit them to DWR for execution. While DWR will be the executing party, such agreements with pipelines shall specifically authorize Utility to act for and on behalf of DWR in nominating gas deliveries, making imbalance trades and managing gas volumes transported under such agreements; provided, however, on the earliest practicable date after the execution of this Agreement, DWR agrees to provide to Utility in writing and in advance of such negotiations any limits, including without limitation any terms, that may be required by DWR.

VII. Gas Scheduling

If permitted under the Allocated Contracts, the Utility shall have full administrative and operational responsibility for scheduling gas deliveries, whether to a specific generating plant or to storage for all gas contracts entered into by DWR or by Utility on DWR's behalf pursuant to this Exhibit B. This function includes use of interstate and intrastate gas pipeline provider websites, confirming via telephone, and all other activities required to move gas from the designated delivery point, as determined by the Utility, to its destination, as determined by the Utility.

VIII. Storage Capacity, Injections and Withdrawals

Utility shall have responsibility for devising plans for gas storage, if Utility, acting as limited agent on behalf of DWR, is to supply gas under Contracts with Fuel Option from a list of approved providers. Following approval of the Utility Gas Supply Plans, Utility shall negotiate firm and/or interruptible agreements with such storage service providers and submit them to DWR for execution. While DWR will be the executing party with DWR remaining the principal under such contracts, such agreements with storage service providers shall specifically authorize Utility to act for and on behalf of DWR in nominating gas injections and withdrawals under such agreements; provided, however, on the earliest practicable date after the execution of this Agreement, DWR agrees to provide to Utility in writing and in advance of such negotiations any limits, including without limitation any terms, that may be required by DWR.

IX. Managing Gas Delivery/Usage Imbalances

For gas that it purchases and transports on behalf of DWR, Utility shall have full administrative and operational responsibility for monitoring and managing the daily status of gas usage vs. gas deliveries (i.e. gas imbalances). In addition, to the extent that gas transportation providers issue operational flow orders or require adjustments in scheduled gas deliveries due to system constraints, Utility, acting as limited agent on behalf of DWR, shall be responsible for compliance with such orders. Utility shall also be responsible for any penalties imposed by gas transportation providers for imbalances caused by Utility, due to its failure to exercise prudent gas management practices.

X. Invoice Review, Approval and Payment

For natural gas, pipeline transportation and storage services it purchases in accordance with this Exhibit B, Utility, acting as limited agent on behalf of DWR, shall have responsibility for receiving invoices from gas, transportation and storage suppliers, reviewing them for accuracy, approving/rejecting invoices for payment and forwarding to DWR for payment; provided, however, on the earliest practicable date after the execution of this Agreement, DWR agrees to cause Utility to be authorized to receive such information from Suppliers. Utility shall provide DWR sufficient documentation to verify payment of the invoices.

XI. Forecasting

Utility shall be responsible for all gas price, demand and supply forecasts which Utility believes are consistent with any accepted gas supply responsibilities.

XII. Risk Management

Utility shall develop and include in its Gas Supply Plans, plans for the hedging of DWR Fuel Supply costs. Final decisions relating to the use or non-use of financial tools such as futures, options and swaps to hedge future gas price exposure on any gas volumes not hedged by Utility under the Utility Gas Supply Plans shall be made and implemented by DWR. Any such contracts executed by DWR on a "portfolio basis" should be utility-specific.

XIII. Market Intelligence

Any and all efforts to obtain, analyze and utilize market intelligence for decision-making purposes shall be the responsibility of Utility.

XIV. Payment of Gas Costs

For natural gas, pipeline transportation, financial hedges and storage services that are purchased and provided by a Supplier under an approved Fuel Supply Plan, DWR shall pay such gas related costs as part of the invoice for commodity, product, or services submitted by the Supplier. For natural gas, pipeline transportation and storage services provided under DWR contracts and administered by Utility on behalf of DWR, DWR shall pay invoices after they have been reviewed and approved for payment by Utility.

XV. Allocation of Existing DWR Gas Contracts

DWR has entered into gas supply, transportation and storage contracts as provided in Attachment 1 to this Exhibit B that have expiration dates after the Effective Date of this Agreement. The administrative and operational control of the contracts listed on Attachment 1 to this Exhibit B will become the responsibility of Utility. This shall include (i) scheduling gas transportation, (ii) confirming gas deliveries, (iii) nominating gas withdrawals from and injections into storage, if applicable, (iv) and reviewing and approving invoices for payment. When approved, invoices shall be transmitted to DWR for payment within 10 days of receipt of invoice from the gas supplier, gas storage or gas transportation provider.

XVI. Pre-existing Financial Hedge Instruments

If DWR has entered into any financial hedge transactions that will remain operable after the Effective Date of this Agreement, DWR shall retain full administrative and operational control over such transactions.

SDG&E EXHIBIT C
SETTLEMENT PRINCIPLES
FOR REMITTANCES AND
SURPLUS REVENUES

EXHIBIT C
SETTLEMENT PRINCIPLES FOR REMITTANCES AND SURPLUS REVENUES

This Exhibit C outlines the principles by which Utility will calculate revenues associated with surplus energy sales and DWR energy delivered to retail customers. This Exhibit C also addresses the information that Utility will provide to DWR to support DWR payment of Contract invoices, and invoices from natural gas supplier(s) for fuel provided to service DWR Contracts where tolling options have been implemented.

This Exhibit C works in conjunction with the applicable Servicing Arrangement with Utility for purposes of determining the remittance amounts by Utility, which will serve as DWR's billing and collection agent.

In accordance with the Contract Allocation Order, this Exhibit C provides that:

- -- Revenues will be allocated for both surplus sales and retail customer deliveries
- -- Revenues will be allocated pro rata, based on dispatched quantities of energy
- -- The principle of balancing least cost economic dispatch while maintaining reliability is reinforced through these revenue allocation protocols.
- -- Surplus sales quantities will be calculated as the difference between Utility's Energy Delivery Obligations (EDO) and the combination of energy from URG and energy dispatched from Contracts.

Where Utility's Energy Delivery Obligations is defined as: (1) Utility's retail load which includes distribution losses, (2) all pumping load, (3) all energy exchange transactions between Utility and counter parties, (3) wholesale obligations existing as of January 1, 2003, (4) transmission losses.

The principles herein, together with the applicable methods and calculations contained in the Servicing Arrangement, form a substantive component of the accounting protocols required to implement the Contract Allocation Order. This Exhibit should also be read in conjunction with Exhibit F ("Data Requirements").

Utility Remittance to DWR

Utility shall remit to DWR an Energy Payment for the delivery of Contract energy to Utility retail customers and a separate payment for DWR's share of Surplus Energy Sales Revenues. The principles for the remittances to DWR of Surplus Energy Sales Revenue and Energy Payment are contained in Sections A and B of this Exhibit C, respectively. The details for determination of the remittances to DWR by Utility are contained in the Servicing Arrangement between the Utility and DWR.

A. Utility Remittance to DWR of Revenue from Surplus Energy Sales

Surplus Energy and Revenues

Surplus energy exists when dispatched supply from Utility portfolio and DWR Contracts exceeds Utility's Energy Delivery Obligations. When such a condition exists, the revenues from the sale of surplus energy shall be shared between Utility and DWR. Surplus sale revenues can occur either through a forward market sale or a delivery of the excess energy into the ISO real time market. In addition to the sharing of surplus energy revenues, the quantity of any surplus energy shall likewise be shared between Utility and DWR, and used in the determination of the Hourly Percentage Factor described in Section I(B).

Surplus energy sales revenues shall be placed by Utility into a separate account (Surplus Sales Fund) to be held in trust and shall be disbursed by Utility to DWR in accordance with the pro-rata allocation principles in Exhibit C and consistent with the provisions of Attachment J of the Servicing Arrangement. For surplus energy sales to third parties, Utility shall apply reasonable credit risk management criteria that is consistent with industry accepted credit standards.

Surplus Energy Quantity

The Surplus Energy quantity shall be determined by subtracting Utility's Energy Delivery Obligations from the sum of dispatched URG energy and dispatched DWR Supply. URG energy shall include dispatched energy from URG, new Utility contracts and Utility market purchases plus adjustments for Ancillary Services and ISO Instructed Energy as described under "Definitions and Adjustments." DWR Supply shall include dispatched energy from DWR must take and dispatchable contracts net of adjustments described below.

DWR Surplus Energy quantity shall be the product of Surplus Energy quantity multiplied by the DWR Surplus Energy Percentage. Utility Surplus Energy quantity shall be the remaining portion of Surplus Energy. Both Utility and DWR Surplus Energy quantities shall be applied to the respective Party's energy supply quantities for determination of the Hourly Percentage Factor described in Section (B).

Surplus Energy Sales Revenues

Surplus Energy Sales Revenues shall be shared between Utility and DWR in the same manner as Surplus Energy.

Forward Market Sale

DWR share of revenues from a forward market sale of surplus energy shall be the product of the net revenue multiplied by the DWR Surplus Energy Percentage. Utility share of these revenues shall be net revenue less DWR share of net revenues. Revenues from a forward market sale shall not be distributed to the Parties until after Utility receives the revenues from the sales and pays sale-related charges. Shared revenues from forward market sales shall be net of transmission costs and broker fees.

ISO Real Time Market Sales

Revenues from delivery of surplus energy to the ISO real time market shall be determined from the product of positive load or supply deviation multiplied by the ISO real time market price. These revenues will be netted against any ISO charges related to the load deviation, including a negative ISO price. Load deviation is determined by subtracting the Utility metered load from the Final Hour Ahead Load Schedule, however only positive quantities, where schedule exceeds meter, reflect surplus conditions for revenue sharing. Supply deviation is determined by subtracting the Final Hour Ahead Supply Schedule (adjusted by real time instructions) from metered supply, however, only positive quantities, where meter exceeds the adjusted schedule, reflect surplus conditions for revenue sharing.

DWR share of revenues from delivery of surplus energy to ISO real time market shall be the product of the net revenues multiplied by the DWR Surplus Energy Percentage. Utility share of these net revenues shall be the net revenue less DWR share of net revenues. Revenues from delivery of surplus energy to the ISO real-time market shall not be distributed to the Parties until after the Utility received payment for final monthly invoice from the ISO for the month in which the surplus energy was delivered.

Over-generation Periods

During periods of over-generation condition as announced by the ISO, surplus sales may be made at very low, zero or even negative prices. In such conditions, the surplus sale revenue calculations as described above still hold. However it is recognized that the sales may result in little or no revenue. Sales could even be done at a cost to the seller. That seller could be Utility or the ISO selling in an "out-of-market" condition. During these conditions, ISO-related charges assigned to Utility for such sales (e.g. - ISO selling out-of-market) are included in the surplus sales revenue as a cost. During over-generation conditions there may be no market in which to sell surplus energy. In that event, or in expectation of that event, Utility shall declare that no valid market exists for surplus energy and shall begin curtailing must-take resources in accordance with Utility's procedures for mitigating over-generation conditions. Such mitigation measures shall be consistent with good utility practice, specifically hydroelectric facilities at spill or near-spill conditions and nuclear facilities scheduled by Utility are the last resources to be reduced in power output.

Over-generation for purposes of this Exhibit C is defined as the condition in which total supply exceeds total loads in the ISO control area.

Revenues or costs from delivery of surplus energy to the ISO real time market under an over-generation condition shall not be distributed to the Parties until after Utility receives payment for final monthly invoice from the ISO for the month in which the surplus energy was delivered.

Calculation of Surplus Energy Percentage

DWR Surplus Energy Percentage shall be equal to the pro rata share of DWR Supply to the sum of Utility Supply and DWR Supply, expressed as follows:

DWR Surplus Energy Percentage = DWR Supply / (Utility Supply + DWR Supply)

Where:

DWR Supply is total energy dispatched from DWR Contracts with

adjustments for transmission losses. Ancillary Services and ISO Instructed Energy transactions described below.
Utility Supply is total energy dispatched from URG, new Utility contracts and Utility market purchases with adjustments for transmission losses, existing wholesale obligations, Ancillary Services and ISO Instructed Energy, exchange transactions, all pumping loads, and ISO Uninstructed Energy as described below.

B. Definitions and Adjustments

Certain energy and capacity transactions, which may be conducted by Utility in its normal course of business, may affect the Utility and DWR Supply quantities used in pro rata calculations.

Exchanges are transactions where energy is delivered to a third party in one period and a similar, but not necessarily equal, amount of energy is returned by third party in a different period. For the purposes of pro rata share calculation, exchanges use energy from the Utility's URG.

Forward Sales are transactions where energy is sold in a forward market to balance supply with demand. In general, for the purposes of remittance determination, forward sales are made using energy from the joint Utility/DWR portfolio.

Ancillary Services are transactions where capacity from certain qualifying resources is sold to ISO for ancillary services rather than being used as energy to serve retail load. Resources from both Utility portfolio and DWR Contracts may qualify for use as ancillary services. Since the capacity used for ancillary services does not serve retail energy load, ancillary service capacity is not considered as a joint Utility/DWR portfolio transaction for the purpose of remittance determination. If Utility or DWR Contract resource capacity is used for ancillary services, the capacity quantity will not be included in the supply quantity of the owning party for the purpose of pro rata share calculations, and owning party will retain all the revenues from the ancillary services as well as all associated transaction costs and ISO charges.

ISO Instructed Energy is a transaction where certain qualifying resources are able to sell energy from unused capacity to the ISO in the real time market. The energy delivered from these resources is directed by the ISO in real time to balance supply and load imbalances on the grid. Either Utility portfolio or DWR Contracts may contain resources that have ability to provide instructed energy to ISO. Since instructed energy is resource specific and does not directly serve the retail load of any utility, instructed energy is not considered as a joint Utility/DWR portfolio transaction for the purpose of remittance determination. If Utility or DWR Contract resources are dispatched as instructed energy, the energy quantity will not be included in the supply quantity of the owning party for the purpose of pro rata share calculations, and owning party will retain all the revenues from the instructed energy as well as all associated transaction costs and ISO charges.

ISO Uninstructed Energy is a transaction where energy is delivered or received from the ISO grid in the real time based on the actual consumption of retail load and actual deliveries of supply resources.

Uninstructed Retail Load Deviations--Uninstructed retail Load Deviations are the difference between scheduled load and metered load. If retail load deviations are positive (schedule exceeds meter), it is considered that any excess supply (less any positive uninstructed supply deviation) was dispatched from the joint Utility/DWR portfolio in excess of quantity needed to serve retail load, and that the ISO credit for the excess supply should be shared pro rata as described above. If retail load deviations are negative (meter exceed schedule), to the extent deviations are not compensated by a positive uninstructed supply deviation, it is considered that Utility had to procure additional supply from ISO real time market. The negative load deviation quantity procured from ISO real time market is considered a Utility market purchase and the quantity will be included in Utility Supply for pro rata share calculation purposes.

Uninstructed Supply Deviations

Uninstructed Supply Deviations are the difference between scheduled supply and metered supply plus an ISO allocation for transmission losses. If Utility's net supply deviations are positive (meter exceeds schedule), to the extent not needed to compensate a negative uninstructed retail load deviation, it is considered that excess supply was a Utility market sale and will not be included in Utility Supply for pro rate calculation purposes. If

Utility's net supply deviations are negative (schedule exceeds meter), to the extent not balanced by a positive uninstructed retail load deviation, it is considered that Utility had to procure additional supply from the ISO real time market. The negative supply deviation quantity procured from the ISO real time market is considered a Utility market purchase and the quantity will be included in Utility Supply for pro rata share calculation purposes.

C. Utility Remittance to DWR for Sales of DWR Energy to Utility Retail Customers -Energy Payment

Utility shall remit to DWR its Energy Payments according to the terms of each Utility's respective Servicing Arrangement.

The DWR Energy Payment is billed by each utility to customers in accordance with the terms of each applicable Utility Servicing Arrangement. The DWR Energy Payment is billed kWhs served by Net DWR Supply at the applicable CPUC approved DWR rate. Net DWR Supply is total DWR Supply less DWR share of surplus energy. The DWR Energy Payment is allocated based on the percentage of energy supplied by DWR to Utility, which is the "Hourly Percentage Factor" multiplied by the retail load of each customer. The Hourly Percentage Factor is determined by calculating the percentage of net energy supplied by DWR to Utility to serve retail load, as expressed below:

Hourly Percentage Factor = Net DWR Supply / (Net Utility Supply + Net DWR Supply)

Where:

Net DWR Supply is DWR Supply quantity used for the determination of DWR Surplus Energy Percentage less DWR share of surplus energy quantity, which is determined by the product of surplus energy multiplied by DWR Surplus Energy Percentage.

Net Utility Supply is Utility Supply quantity used for the determination of DWR Surplus Energy Percentage less Utility share of surplus energy quantity, which is total surplus energy less the DWR share of surplus energy quantity.

In the Event of any conflict between the formulas and procedures in this Exhibit C and the formulas and procedures in Utility's Servicing Arrangement, those contained in Utility's Servicing Arrangement shall govern.

II. Bilateral Settlement

Under the Contract Allocation Order DWR remains financially obligated for the Contracts. DWR will continue to pay suppliers and this requires DWR to apply appropriate procedures and controls to ensure that payments are made accurately and in a timely manner. Information supporting Contract settlements will be provided by Utility, and additional information may also be required to address contract performance issues (such as availability and other items as discussed in Exhibit E) and to allow DWR to settle disputes in an appropriate manner.

DWR requires sufficient information to support payment requests so that it can meet the accountability requirements of the State Controller's Office and the State Auditor, and simultaneously comply with the applicable statutes concerning disbursement of public monies. The Utility shall reconcile schedules with suppliers invoice. DWR shall make the associated payments to suppliers after performing its verification, and Utility will provide the data as required in Exhibit F to allow it to perform these duties in a timely manner as set forth herein.

DWR shall continue to perform validation of settlement data and invoices and pay Contract costs directly to the suppliers upon validation of invoices.

III. Fuel Cost Verification and Settlement

Exhibit B provides a detailed discussion concerning Utility's responsibility for fuel management. DWR will continue to pay fuel suppliers and others involved in providing fuel management services for the delivery of fuel for those DWR Contracts where the Fuel Option has been elected. Consistent with the above, Utility will perform settlements activities to reconcile quantities and associated charges, and DWR will perform verification, audit and monitoring to support its disbursement of funds. Utility will comply with the requirements contained in Exhibit F to provide DWR with the necessary information to apply appropriate procedures and controls to ensure that fuel payments and payments for fuel management services are made accurately and in a timely manner and to allow DWR to settle disputes in an appropriate manner.

SDG&E EXHIBIT D
ISO SCHEDULING COORDINATOR CHARGES

EXHIBIT D

ISO SCHEDULING COORDINATOR CHARGES

The financial obligation for ISO charges incurred after the Effective Date will be allocated to the Utility, unless otherwise extended under the existing letter agreement with DWR related to the ISO charges and any future Applicable Commission Orders. Unless specifically provided in Exhibit C hereto, all ISO charges incurred after the Effective Date attributable to load and resources shall be the responsibility of Utility.

Utility agrees that any refunds, reruns or credits through the ISO attributable to costs incurred by DWR for trade dates beginning February 7, 2001 up to the Effective Date shall belong to DWR and Utility shall take all necessary action to remit such refunds or credits to DWR within reasonable time. In addition, DWR shall be responsible for any ISO charges incurred during this period pursuant to the existing letter agreement between the Parties. Utility shall invoice DWR for such ISO charges within a reasonable period of time and DWR shall pay Utility for such ISO charges within 10 days of receipt of such invoice. Without making any assurances as to Commission action, DWR agrees to take appropriate action to ensure that such refunds or credits are applied consistent with DWR's Revenue Requirement cost allocation method for the same trade dates.

SDG&E EXHIBIT E
CONTRACT MANAGEMENT AND
ADMINISTRATION PROTOCOLS

EXHIBIT E

CONTRACT MANAGEMENT AND ADMINISTRATION PROTOCOLS

DWR will retain all contract management, administration and monitoring responsibilities for the Contracts, including due diligence, performance testing, contract performance assessment, formal correspondence and notifications with Suppliers, exercise of contract options, contract interpretation and dispute resolution, and financial reporting. Upon development by Utility and DWR in the future to a transition plan that transfers the Due Diligence and Performance Test Monitoring functions set forth in this Exhibit E from DWR to the Utility, , including a transition schedule, and a transition plan , Utility agrees to submit such transition plan to the Commission as an amendment to this Exhibit E for approval by the Commission. Upon agreement of the Parties to an acceptable transition plan and the Commission approval of Utility submitted transition plan, the agreed upon functions will transfer from DWR to the Utility ("the Transition Date").

I. Due-Diligence

The Due Diligence function assesses the progress of permitting, construction and performance capability of new generating facilities under to the Contracts. Due Diligence includes (i) monitoring activities associated with the development, construction, and performance of new generating facilities; (ii) identification and tracking of key projects milestones including permitting, equipment procurement, construction, commissioning, and performance testing; (iii) coordination with permitting agencies and the Suppliers, review of project documents, physical inspections, and witnessing of acceptance tests, (iv) verification that the new facilities can perform in a manner that is consistent with the obligations under the appropriate Contract and (v) review and approval of commercial operation dates and documentation.

II. Performance Test Monitoring

A. Annual Performance Tests

Annual Performance Tests verify ongoing compliance with the Contracts and establish plants capacities and efficiencies that are used to calculate contract payments, either for capacity or energy. Annual Performance Test responsibilities generally consist of (i) verification of testing procedures, (ii) witness of performance tests, (iii) review of test results and test reports for compliance with Contract terms and conditions, and (iv) identification of contract non-compliance for dispute resolution with the Supplier. Prior to the Transition Date, the Utility will cooperate and assist DWR with scheduling of upcoming Annual Performance Tests, and the Utility may have its staff witness such testing.

B. Scheduled Performance Tests

Prior to the Transition Date, on occasion, DWR may request that Utility schedule a peaking or dispatchable generating facility for testing (to assure that such generation facility is available according to the terms of the contract between such generation facility and DWR). The utility will cooperate and shall coordinate with the DWR on a mutually acceptable date for performance of the test. On the date agreed upon, the Utility shall schedule the specified facility or unit for operation to test the availability, reliability, and performance of the scheduled unit.

C. Test Procedures and Protocols

Prior to January 1, 2003, Utility shall meet with DWR staff to review, discuss, and verify test procedures and protocols developed by DWR.

III. Contract Performance Assessments

DWR shall continue to perform an after-the-fact review ("Performance Assessment") of each Contract on a periodic basis. The purpose of the Performance Assessment is to assess, analyze, and document the overall performance of each Supplier, assure that the Supplier is satisfying the terms and conditions of their respective contract(s), and identify potential issues, disputes, and other matters that may require corrective action by either Utility or DWR as part of contract administration.

IV. Other Administrative Matters

A. Correspondence with Suppliers

Utility and DWR agree to copy each other on all written correspondence and written notifications sent to or received from a Supplier of an Allocated Contract or Interim Contract related to the activities described in this Exhibit E. The Parties agree to provide additional information as requested related to verification and support of the activities described in this Exhibit E.

B. Reports

Results of the activities described in this Exhibit E will be documented by DWR in written reports ("Reports") and shall be discussed periodically between DWR and the Utility. Such Reports may include, but are not limited to, summary of test results, status of projects, recommendations for operational changes, procedural changes, dispute resolution, and results of Performance Assessments.
Such Reports, documentation, or other material developed by either Party shall be shared and reviewed with the other Party on a timely basis.

EXHIBIT 10.07

Decision 02-12-070 December 19, 2002

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

The application of SAN DIEGO GAS & ELECTRIC (U 902 E) for approval of servicing agreement between the State of California Department of Water Resources ("DWR") and SDG&E Company Pursuant to Chapter 4 of the Statutes of 2001 (Assembly Bill 1 of the First 2001-2002 Extraordinary Session).	Application 01-06-039 (Filed June 22, 2001)

OPINION APPROVING THE 2003 SERVICING ORDER CONCERNING SAN DIEGO GAS & ELECTRIC COMPANY AND THE CALIFORNIA DEPARTMENT OF WATER RESOURCES

Summary

On October 8, 2002, the California Department of Water Resources (DWR) submitted to this Commission a memorandum and proposed modifications to the "First Amended and Restated Servicing Agreement" (Amended Servicing Agreement) between DWR and San Diego Gas & Electric Company (SDG&E). DWR's submission was made in response to D.02-09-053 (the "Contract Allocation Decision"), which directed DWR and SDG&E to negotiate appropriate modifications to the Amended Servicing Agreement as a result of the allocation of energy from, and operational responsibility for, DWR's electricity contracts to SDG&E and the other two large electric utilities.

Today's decision approves a modified version of DWR's proposed modifications, which we have labeled as the "2003 Servicing Order Concerning State of California Department of Water Resources And San Diego Gas & Electric Company" (Servicing Order). Because the changes that DWR proposed, and that we here approve with modifications, were not agreed to by SDG&E, we are constrained to issue a Servicing Order rather than approve a Servicing Agreement. Appendix A of this decision contains a marked version of the revisions to the Servicing Order that we approve today. Appendix B of this decision is a "clean" copy of the approved Servicing Order. SDG&E is ordered to comply with the terms and conditions of the Servicing Order. The Servicing Order sets forth the terms and conditions under which SDG&E will provide the transmission and distribution of DWR-purchased electricity, as well as billing, collection, and related services on behalf of DWR. The Servicing Order also addresses DWR's comp ensation to SDG&E for providing those services.

Today's Servicing Order is needed because DWR and SDG&E have been unable to negotiate a mutually agreeable servicing arrangement. Due to the upcoming date when SDG&E is to assume operational control of the DWR contracts allocated to it, a Servicing Order needs to be put into place prior to year's end.

Background

In January 2001, in response to the energy crisis facing California, the Legislature gave DWR the authority to purchase electricity and sell it to the retail customers of California's electric utilities. This authority was provided for in Assembly Bill 1 of the First Extraordinary Session of 2001-2002 (Stats. 2001, Ch. 4) (AB X1).

In March 2001, the Commission ordered SDG&E to segregate, and hold in trust for the benefit of DWR, certain amounts its customers had paid for DWR's electricity. (D.01-03-081.) This arrangement was formalized in the "Servicing Agreement Between State of California Department of Water Resources and San Diego Gas & Electric Company," which was approved by the Commission with certain modifications in D.01-09-013.

As a result of D.01-09-013, D.02-02-051, and D.02-02-052, SDG&E and DWR discussed and negotiated amendments and restatements to the Servicing Agreement. These changes were reflected in the Amended Servicing Agreement, which the two parties signed on March 29, 2002. Subsequently, SDG&E sought Commission approval of the Amended Servicing Agreement by filing a petition for modification of D.01-09-013. The Commission granted SDG&E's petition and approved the Amended Servicing Agreement in D.02-04-048.

In D.02-07-038, the Commission approved SDG&E's second petition to modify D.01-09-013. This petition sought Commission approval of "Amendment No. 1" to the Amended Servicing Agreement. Thus, prior to today's decision, the existing servicing arrangements between SDG&E and DWR are composed of the Amended Servicing Agreement and Amendment No. 1.

Under AB X1, DWR's authority to contract for electricity purchases expires on January 1, 2003. (Water Code Sec. 80260.) Rulemaking (R.) 01-10-024 was initiated by the Commission to allow the electric utilities to resume the responsibility of procuring electricity for their customers. In D.02-09-053, the Commission ordered SDG&E, and the other two large electric utilities, to assume all of the operational, dispatch, and administrative functions for the electricity contracts that DWR had entered into, effective January 1, 2003. D.02-09-053 also allocated the DWR contracts to the resource portfolios of the three utilities, who are to schedule and dispatch the contracts in a least-cost manner.

As a result of the assumption of the operational duties for the DWR contracts, the Contract Allocation Decision recognized that the "servicing arrangements" that DWR had entered into with SDG&E, would need to be altered. (D.02-09-053, pp. 15, 59.) In Ordering Paragraph 3 of D.02-09-053, DWR and SDG&E were directed to negotiate appropriate modifications to their servicing arrangements, and DWR was directed to "submit its proposed modifications" by October 1, 2002. DWR and the three electric utilities were also directed to jointly file proposed operational agreements and proposed standards for reasonableness review by October 1, 2002.

The three utilities requested an extension of the submission date for the proposed modifications to the servicing arrangements and proposed operational agreements. The Commission's Executive Director, in a letter dated September 27, 2002, granted an extension of one week, to October 8, 2002.

In response to the submissions ordered in D.02-09-053, on October 8, 2002, DWR electronically transmitted to the Commission, and to the service list, a memorandum from Peter Garris of DWR, along with the proposed modifications to the existing servicing arrangements for SDG&E, and the other two utilities. The document containing DWR's proposed modifications to SDG&E's servicing arrangements is labeled "2003 Servicing Agreement Between State of California Department of Water Resources And San Diego Gas & Electric Company." DWR also transmitted two other documents, one which contains Attachments A through H of the Servicing Order, and the other which contains Attachment J of the Servicing Order.

Due to the earlier extension by the Executive Director, the assigned administrative law judge (ALJ) issued a ruling on October 10, 2002, allowing interested parties additional time to submit comments on the proposed modifications to SDG&E's servicing arrangements, and reply comments. SDG&E filed comments and reply comments on October 18, 2002 and October 23, 2002, respectively. On October 23, 2002, DWR transmitted a memorandum entitled "Comments Concerning Submissions Requested by the California Public Utilities Commission Decision 02-09-053."

Summary of Proposed Modifications to
the Amended Servicing Agreement

The proposed modifications to the Amended Servicing Agreement and related attachments have been compared to the Amended Servicing Agreement that was approved in D.02-04-048, and to Amendment No. 1 approved in D.02-07-038. In addition, the proposed modifications have been reviewed in light of the Contract Allocation Decision. Appendix A of this decision reflects the proposed modifications to the Amended Servicing Agreement through the use of underlining and strikeout markings.

The proposed modifications fall into the following categories:

- Definitions and requirements relating to the DWR contracts allocated to SDG&E in the Contract Allocation Decision.
- Definitions and requirements relating to the surplus energy sales and remittances that SDG&E will be responsible for.
- Definitions and requirements relating to the Operating Order.

- Incorporation of Amendment No. 1 into the modified version of the Amended Servicing Agreement.
- Certain attachments to be provided by SDG&E in Service Attachment 2.
- Incorporation of Attachment F, approved in D.02-07-038, into the modified version of the Amended Servicing Agreement.

In addition to the proposed modifications, additional changes have been made to the Amended Servicing Agreement and the related attachments. These additional changes are described in the discussion section below, and also reflect that SDG&E is being ordered to provide the services in accordance with the attached Servicing Order and that an Operating Order is expected to be approved, rather than an Operating Agreement.

Position of the Parties

A. DWR

According to DWR's October 8, 2002 memorandum, DWR distributed the proposed modifications to SDG&E's servicing arrangements on October 3 and 4, 2002. As of October 8, 2002, DWR was unable to ascertain whether the proposed modifications were acceptable to SDG&E.

DWR has proposed modifying the Amended Servicing Agreement by making certain changes to the accounting and reporting procedures. According to DWR, these changes are found in Attachments C and J of the Servicing Order, and parallel accounting and reporting provisions are contained in Exhibits C and F of the Operating Order. DWR states that these accounting and reporting procedures are consistent with the policy set forth in the Contract Allocation Decision.

In its October 23, 2002 memorandum, DWR noted that, consistent with AB X1 and the Contract Allocation Decision, that it would still be subject to continuing obligations with respect to the DWR contracts. In particular, these obligations include:

- Servicing the bonds as issuer;
- Managing legal and financial obligations under its long-term contracts;
- Ensuring the integrity of its revenues; and
- Fulfilling its substantial reporting obligations associated with the above.

DWR states that it is working to ensure that there is an efficient and timely transition to the utilities of the operational functions of the DWR contracts, while ensuring that DWR is able to fulfill its continuing obligations. To accomplish this goal:

> "DWR believes that certain principles and arrangements must be established regarding utilities' performance of certain functions under the allocated DWR long-term contracts on behalf of DWR. The operating agreement is a compilation of such principles and arrangements that DWR believes are necessary to achieve these goals.

. . .

> "In preparing the operating agreement, DWR's objective has been to minimize DWR's involvement in the utilities' operation of the integrated portfolio, consisting of utility and allocated DWR contract resources, and to allow the utilities to make substantially all the operating decisions. The operating agreement is intended to provide appropriate mechanisms that allow the utilities to optimize the use of the integrated portfolio of resources on a service territory basis. . . After the operational transition, DWR will continue to be legally and financially responsible for the direct costs under the allocated DWR long-term contracts, including gas-related costs. As a result, DWR needs to receive timely reporting of data outlined in Exhibit F of the operating agreement.
>
> "To implement checks and balances while operating the integrated portfolio, DWR has proposed certain accounting and revenue sharing principles in Exhibit C of the operating agreement. DWR believes that the proposed accounting and revenue sharing principles provide greater certainty of revenues and cash flows to the utilities and DWR and, accordingly, aid the utilities in their quest for creditworthy status. Finally, DWR believes that the pro rata revenue-sharing methodology articulated in the Contract Allocation Decision and further reflected in DWR's accounting and revenue sharing principles results in an equitable sharing of risk and reward. The information and data being requested under Exhibit F of the operating agreement are to facilitate DWR's verification of the utilities' remittances to DWR and costs incurred under the allocated contracts rather than to conduct an operational review of the utilities decisions.
>
> "At this time, DWR does not believe that there is a consensus on the accounting and revenue sharing principles proposed by DWR. . . . The resolution of the issues related to the accounting and revenue sharing principles will require a significant shift from the existing remittance policy and DWR believes that such a policy implementation can only be achieved with the Commission's support and active involvement." (DWR October 23, 2002 Memorandum, pp. 1-2.)

A. SDG&E

SDG&E's comments emphasize three points that the Commission should keep in mind while considering the proposed modifications to the Amended Servicing Agreement. First, that DWR and SDG&E are still continuing to negotiate, and that more time is needed to reach a consensus with DWR concerning the proposed modifications. Second, that the proposed modifications to the Amended Servicing Agreement are duplicative or in conflict with the proposed Operating Agreement. Whatever is adopted in the proposed Operating Agreement will affect certain provisions in the proposed modifications to the Amended Servicing Agreement. And third, that the proposed modifications to the Amended Servicing Agreement should provide that any revenues for surplus sales will be net of expenses.

SDG&E's comments also lists a series of concerns with the proposed modifications to the Amended Servicing Agreement and to the attachments. These issues fall into the following categories:

- Text changes to reflect the pro rata sharing of revenues contained in D.02-09-053.
- Text changes to reflect whether an agency relationship is created from the surplus sales made from a pro rata resource pool of DWR and investor owned utility energy, and indemnification and waiver of liability issues.
- Text changes regarding credit risk management and the associated incremental costs related to the sale of surplus energy.
- When SDG&E should forward DWR's share of the surplus energy sales revenues.
- Changes to Service Attachment 2, and Attachments B, F and G.

Discussion

In deciding whether we should approve the proposed modifications to the Amended Servicing Agreement and related attachments, the Commission is mindful of the course of action we have taken in R.01-10-024 and in D.02-09-053. One of the goals of R.01-10-024 is to allow the utilities "to resume purchasing electric energy, capacity, ancillary services and related hedging instruments to fulfill their obligation to serve and meet the needs of their customers." (R.01-10-024, p. 1.)

In order for SDG&E and the other utilities to undertake the operational responsibilities associated with the allocated DWR contracts beginning on January 1, 2003, certain operational arrangements and servicing arrangements need to be in place. With less than one month to go before the utilities are to take over the operational responsibilities for the DWR contracts, DWR and SDG&E have been unable to agree on a mutually acceptable servicing arrangement. To ensure a seamless transition of the DWR contracts allocated to SDG&E, while ensuring that DWR's legal and financial responsibilities for the DWR contracts continue to be fulfilled, it is imperative that servicing arrangements be in place before the end of 2002.

D.02-09-053 also required DWR to submit proposed operational agreements. As noted in the positions of the parties, certain provisions of the proposed operational agreement that DWR submitted may affect certain provisions of the proposed modifications to the Amended Servicing Agreement and the related attachments. The proposed operating agreement is being considered by the Commission in R.01-10-024. Since DWR and the utilities have been unable to mutually agree on a proposed operational agreement, we believe that the Commission will concurrently adopt an Operating Order when a Servicing Order for SDG&E is adopted.

On December 9, 2002, SDG&E filed its comments on the draft decision regarding the Servicing Order, and DWR submitted a memorandum on the three draft decisions regarding the Servicing Order. DWR's memorandum included a copy of "Amendment No. 2 To The First Amended and Restated Servicing Agreement Between The State of California Department of Water Resources and San Diego Gas & Electric Company" (Amendment No. 2). DWR states that Amendment No. 2 is intended to effect changes to the Agreement requested in D.02-11-074, the Bond Charge Decision. That decision, among other things, ordered SDG&E to make changes to its billing systems to impose the bond charges. As of December 9, 2002, SDG&E and DWR were in the process of executing Amendment No. 2. DWR states that it agrees to the provisions of Amendment No. 2, and requests that the Commission approve Amendment No. 2, or that the provisions of Amendment No. 2 be incorporated in the Commission's final 2003 Servicing Order decision.

DWR's December 9, 2002 memorandum also states that it reserves comment on the draft decisions which would adopt the Servicing Orders. DWR considers it premature to comment on these draft decisions because DWR submitted a request to the Commission on December 9, 2002, requesting that the Commission order the utilities to enter into an operating agreement with DWR pursuant to Water Code Sec. 80106(b). DWR states that any Servicing Order adopted by the Commission must be consistent with the operating agreement request.

SDG&E's December 9, 2002 comments note that it has agreed with DWR on the terms of Amendment No. 2, and that it anticipates submitting a signed copy of Amendment No. 2 to the Commission with SDG&E's December 16, 2002 reply comments. SDG&E states that the purpose of Amendment No. 2 is to revise the procedures found in the existing Servicing Agreement, and that the "revisions contemplate the manner by which SDG&E collects the DWR bond charges from its customers and remits them to DWR and the collection of fees by SDG&E for undertaking these agency services." (SDG&E Comments, p. 4.)

Amendment No. 2 makes four changes to SDG&E's existing Amended Servicing Agreement. The first change is to add Section 7.5 to the Amended Servicing Agreement. Section 7.5 provides for a reconciliation payment in the event there is a change in the applicable law, or a payment procedure is inconsistent with applicable law. The second change makes a revision to Section 7.4 of the Amended Servicing Agreement to reference the addition of Section 7.5. The third change is a revised Attachment C to the Amended Servicing Agreement. The new Attachment C revises the format of the daily and monthly reports to include additional information about the implementation of the bond charges. The fourth change is a revised Attachment G to the Amended Servicing Agreement. As revised, Attachment G provides an estimate of SDG&E's implementation costs associated with the DWR bond charge, and the reimbursement procedure that SDG&E and DWR will follow.

We will incorporate the provisions of Amendment No. 2, as agreed to by DWR and SDG&E, into the Servicing Order that we adopt today. The revisions in Amendment No. 2 enable SDG&E to carry out the Commission's directives contained in the Bond Charge Decision.

We now turn to SDG&E's concerns with the proposed modifications to the Amended Servicing Agreement.

SDG&E's first concern is that the use of "deemed" in sections 1.51 and 2.2.(c) of Amended Servicing Agreement are unnecessary because it may conflict with the pro rata sharing of revenues ordered in D.02-09-053 and because Attachments H and J specify how to determine the amount of energy provided by DWR and SDG&E.

We agree with SDG&E. Attachments H and J explain how to determine the amount of energy provided by DWR and SDG&E. The use of the term or phrase starting with "deemed" could be interpreted to mean that another calculation of DWR energy is possible. We will delete the references in sections 1.51. and 2.2.(c).

SDG&E's second concern is whether the utility is acting as DWR's agent for surplus sales, as found in the proposed modification to sections 2.3., 3.5. and 14.1. SDG&E urges the Commission to modify the draft decision to state that SDG&E's agency role cannot be allowed to interfere with providing service to SDG&E's customers. SDG&E states that its primary fiduciary obligation is to undertake its operational responsibilities, whether of its assets or of the allocated DWR contracts, in the best interests of the utility's ratepayers and shareholders."

We decline to delete those references. The draft decision regarding the Operating Order notes that the utilities are operating as DWR's agent for limited purposes, and that it reflects the nature of the capacity in which the utilities are undertaking these functions.

SDG&E's third concern is with the costs associated with credit risk management and the incremental costs associated with the sales of surplus energy. SDG&E states that the provisions of Section 3 of the Operating Order would place the credit risk management and costs on SDG&E. SDG&E states that credit risk management should be in the Operating Agreement, and not in the Servicing Order. If costs are incurred from the credit management, SDG&E states that DWR must share in these costs and that they should be included in the Servicing Order as part of the surplus energy sales revenue remittance calculation. SDG&E asserts that costs that are incremental to the sale should be attributed to the sales and any revenues should be net of any sales costs. SDG&E contends that under AB X1, SDG&E cannot be given any financial responsibility for DWR's costs. In addition, SDG&E contends that AB 57 requires that its creditworthiness cannot be impaired. SDG&E raised similar arg uments with respect to the Operating Order.

We will accept DWR's proposed modification to sections 3.1(c) and 3.1(d) of the Servicing Order. This is consistent with the Commission's goal of reducing the utilities' reliance on the use of state resources to fulfill their obligations to serve customers. As noted in the Operating Order decision, the collateral requirements are not imposed by the DWR Contracts, but rather by exogenous variables such as the ISO tariff. With respect to the incremental costs associated with surplus energy sales, the Operating Order decision addresses the recovery of those costs.

SDG&E's fourth concern is with sections 3.5 and 12, and whether DWR must provide indemnification or a waiver of liability in situations involving the sale of surplus energy and disputes with third-party purchasers. Section 12 of the Amended Servicing Agreement addresses indemnification issues, but does not specifically address how specific situations would be handled. SDG&E contends that the draft decision should be modified to state that DWR must provide indemnification or waiver of liability if SDG&E is going to act on DWR's behalf. Neither DWR or SDG&E have proposed language to clarify the indemnification issue. We refrain from crafting additional indemnification language for the Servicing Order. This issue is best left to DWR and SDG&E to work out.

The fifth concern of SDG&E is the timing of when SDG&E shall make its remittances to DWR for the sale of surplus energy. Under section 4.2(g) and Attachment J, SDG&E is to remit DWR's share of the surplus sales revenues on the first business day after the 20th day of the month following each delivery month. SDG&E takes the position that it should not have to advance any funds to DWR, and that it should only remit DWR's share of the surplus sales revenues when the purchasers of the power pay SDG&E.

In SDG&E's comments to the draft decision, SDG&E points out that the provision in Section 4.2(g) of the proposed Servicing Order requiring SDG&E to remit surplus sales revenue to DWR on the 20th of the month following delivery could result in SDG&E having to incur the cost of a 40- to 55- day float. SDG&E states that this would require a revenue increase for additional cash working capital in SDG&E's next cost of service filing, which is contrary to, and not permitted under AB X1. SDG&E also points out that in DWR's December 5, 2002 memorandum to the Commission, that DWR indicated that surplus sales revenue should be remitted on "an actual receipts basis" and not on a "cost incurred" basis. SDG&E states that the draft decision regarding the Operating Order refers to the "receipts" concept, while the Servicing Order uses an obsolete reference to 20 days.

In D.02-09-053, at page 46, we stated that although DWR remains financially responsible for paying all contract-related bills, we expect that the utilities will "verify the invoices and instruct DWR to pay the bills." This statement suggests that SDG&E should not have to advance funds to DWR before DWR has to pay its invoices. The provisions in section 4.2(g) and Attachment J would require SDG&E to remit payments within 20 days of each delivery month, which presumably does not match up with when the invoices are due. Exhibit C of the Operating Order, which is entitled "Settlement Principles For Remittances And Surplus Revenues," provides at page C-3 that the: "Revenues from a forward market sale shall not be distributed to the Parties until after Utility receives the revenues from the sales and any sale-related charges." In reference to "ISO Real Time Market Sales," Exhibit C states that the: "Revenues from delivery of surplus energy to the ISO real time market shall not be distributed to the Parties until after Utility receives payment for final monthly invoice from the ISO for the month in which the surplus energy was delivered." Both of the quoted passages mean that SDG&E should not have to remit revenues from the energy sales to DWR until SDG&E has received payment. Accordingly, we shall change the reference in Section 4.2(g) of the Servicing Order regarding the 20 days to make it consistent with Exhibit C of the Operating Order.

Attachment J of the proposed Servicing Order is premised on remitting a preliminary amount of the surplus energy sales revenues to DWR on the first business day after the 20th day of the month. However, as discussed above, Exhibit C of the Operating Order specifies that revenues from forward sales, and sales to the ISO, are to be remitted to DWR after the utility has received payment. In order to make the Servicing Order consistent with the Operating Order, proposed Attachment J should be deleted from the Servicing Order that we adopt in this decision. In addition, other references to Attachment J that appear in the following sections of the Servicing Order shall also be deleted: 1.30.5.; 2.2.(d); 2.2.(f); 2.5.; 4.1.; 4.2.(g); 4.2.(h); 5.1.; 5.5.; and 14.17.

SDG&E's sixth concern is with the proposed modifications to sections H and I of Attachment B. SDG&E notes in its comments that section H.2. "should be deleted since this deals with the reconciliation SDG&E just completed."

We note that in DWR's October 8, 2002 transmittal of the proposed modifications to Attachment B, that section H.2. had already been deleted. As for the proposed modifications to section I of Attachment B, the addition of this section is consistent with the Post-Transition Remittance Methodology that is to take effect on and after the effective date of the Operating Order as provided for in Attachment H.

The seventh concern of SDG&E is that SDG&E has not included the Commission approved version of Attachment F in its proposed modifications. We have compared DWR's submission of Attachment F to the version that was approved in D.02-07-038. DWR's submission is virtually identical to what was approved in D.02-07-038, except that DWR's October 8, 2002 submission does not contain the table entitled "Summary Results of 20/20 Conservation Program: August 2002." We have indicated on Appendix A and Appendix B that the table approved in D.02-07-038 should be used in Attachment F.

SDG&E's eighth concern is with Attachment G, the DWR billing agent cost estimates. SDG&E states that this chart is outdated because it does not include bond charges and exit fees. SDG&E states that this section will need to be updated once these charges and fees are known. With that understanding, we recognize that Attachment G will need to be changed to reflect these additional charges and fees.

SDG&E's ninth concern is with the information that DWR wants in Service Attachment 2. SDG&E states that it is working with DWR to determine what kind of information DWR wants. DWR's October 8, 2002 submission only included the one page "Service Attachment 2," which described the "Title" of seven sections. DWR's Service Attachment 2 also notes that this is "To be provided by Utility." We will retain the Service Attachment 2 page as part of the Servicing Order, with the understanding that DWR and SDG&E will need to discuss what kind of information DWR wants from SDG&E.

The majority of the proposed modifications to the Amended Servicing Agreement reflect the actions taken in the Contract Allocation Decision, and are also linked to the proposed operating agreement. All of the proposed modifications, as shown in the attached Servicing Order and as discussed above, are consistent with the directives ordered in D.01-09-013, D.02-02-051, D.02-02-052, and D.02-09-053.

Since DWR and SDG&E have been unable to timely agree on a mutually acceptable modified Amended Servicing Agreement, we have further modified DWR's proposed modifications to the Amended Servicing Agreement to turn the document into a Servicing Order. The marked and clean versions of the Servicing Order, which are attached to this decision as Appendix A and Appendix B, are approved. SDG&E shall be directed to comply with the terms and conditions of the attached Servicing Order.

We note that today's approval of the Servicing Order does not prevent DWR and SDG&E from negotiating a mutually agreeable modified servicing agreement in the future and bringing such an agreement to us for approval. However, due to the approaching deadline for when SDG&E is to take over the operational aspects of the DWR contracts allocated to SDG&E, the attached Servicing Order is needed so that the operational transition for the DWR contracts can proceed smoothly.

Southern California Edison Company (SCE) raised a point in its comments to the draft decision regarding SCE's Servicing Order that has applicability to SDG&E as well. SCE states in its comments that it has had discussions with DWR as to the possible terms and conditions that could be included in the Amended Servicing Agreement. Although it is unclear at this point whether such discussions will lead to an agreement, SCE seeks clarification from the Commission that SCE be allowed to seek the termination of any Servicing Order that may be adopted, with an executed agreement between SCE and DWR "which substantially and fundamentally comport with the terms and conditions set forth in the . . .Servicing Order and the related attachments as they then exist." (SCE December 9, 2002 Comments, p. 11.)

We are receptive to reviewing a mutually agreeable servicing arrangement between SDG&E and DWR, so long as the terms do not substantially deviate from what's adopted in today's servicing order. Should SDG&E and DWR negotiate such an arrangement, SDG&E is free to request that the Commission consider replacing the Servicing Order adopted in today's decision with the mutually agreeable arrangement.

Rehearing and Judicial Review

This decision construes, applies, implements, and interprets the provisions of AB X1. Pursuant to Public Utilities Code Sec. 1731(c) any application for rehearing of this decision must be filed within 10 days of the date of issuance of this decision, and the provisions of Public Utilities Code Sec. 1768 are applicable to any judicial review of this decision.

Comments on Draft Decision

Pursuant to Public Utilities Code Sec. 311(g)(1) and Rule 77.7 of the Commission's Rules of Practice and Procedure, the draft decision of the ALJ was mailed to the parties on November 20, 2002. The comments on the draft decision have been reviewed, and appropriate changes have been made to the Servicing Order and the attachments.

Assignment of Proceeding

Loretta M. Lynch is the Assigned Commissioner and John S. Wong is the assigned ALJ in this proceeding.

Findings of Fact

1. In response to D.02-09-053, on October 8, 2002, DWR submitted a memorandum and its proposed modifications to the Amended Servicing Agreement.
2. Prior to today's decision, the existing servicing arrangement between DWR and SDG&E are composed of the Amended Servicing Agreement and Amendment No. 1.
3. D.02-09-053 allocated the DWR contracts, and ordered SDG&E and the other two large electric utilities, to assume all of the operational, dispatch, and administrative functions for the allocated electricity contracts, effective January 1, 2003.
4. The proposed modifications to the Amended Servicing Agreement and related attachments have been compared to the Amended Servicing Agreement that was approved in D.02-04-048, to Amendment No. 1 approved in D.02-07-038, and have been reviewed in light of the Contract Allocation Decision.
5. One of the goals of R.01-10-024 is to allow the utilities to resume purchasing electric energy, capacity, ancillary services and related hedging instruments to fulfill their obligation to serve and meet the needs of their customers.
6. In order for SDG&E and the other utilities to undertake the operational responsibilities associated with the allocated DWR contracts beginning on January 1, 2003, certain operational arrangements and servicing arrangements need to be in place before that date.
7. Certain provisions of the proposed operating agreement may affect certain provisions of the proposed modifications to the Amended Servicing Agreement and related attachments.
8. The proposed operational agreement is being considered by the Commission in R.01-10-024.
9. The concerns of SDG&E over the proposed modifications to the Amended Servicing Agreement and related attachments have been reviewed and considered, and appropriate changes have been made as discussed in this decision.
10. Notwithstanding today's approval of the Servicing Order, DWR and SDG&E are free to submit a mutually agreeable modified servicing agreement for our approval.

Conclusions of Law

1. All of the proposed modifications to the Amended Servicing Agreement and the related attachments are consistent with the directives ordered in prior Commission decisions.
2. Since DWR and SDG&E have been unable to timely agree on a mutually acceptable modified Amended Servicing Agreement, the Commission has made additional modifications to convert the modified Amended Servicing Agreement into a Servicing Order.
3. The Servicing Order attached to this decision should be approved.
4. SDG&E should be directed to comply with the terms and conditions contained in the approved Servicing Order.

ORDER

IT IS ORDERED that:

1. The marked version, attached hereto as Appendix A, and the clean version, attached hereto as Appendix B, of the "2003 Servicing Order Concerning State of California Department of Water Resources And San Diego Gas & Electric Company" (Servicing Order) is approved.
2. San Diego Gas & Electric Company shall comply with all of the terms and conditions of the approved Servicing Order.
3. This proceeding is closed.

This order is effective today.

Dated December 19, 2002, at San Francisco, California.

LORETTA M. LYNCH

President

HENRY M. DUQUE

CARL W. WOOD

GEOFFREY F. BROWN

MICHAEL R. PEEVEY

Commissioners

2003 SERVICING ORDER

CONCERNING

STATE OF CALIFORNIA
DEPARTMENT OF WATER RESOURCES

And

SAN DIEGO GAS & ELECTRIC COMPANY

THIS ORDER HAS BEEN ISSUED BY THE CALIFORNIA PUBLIC UTILITIES COMMISSION ("COMMISSION") FOR USE BETWEEN THE STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES ("DWR") AND SAN DIEGO GAS & ELECTRIC COMPANY ("UTILITY").

Date of Commission Approval: ________________________

Effective Date: ________________________

2003 SERVICING ORDER

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ATTACHMENTS

2003 SERVICING ORDER

THIS 2003 SERVICING ORDER (the "Servicing Order") concerns the State of California Department of Water Resources ("DWR"), separate and apart from its powers and responsibilities with respect to the State Water Resources Development System, and San Diego Gas & Electric Company, a California corporation ("Utility"). This Servicing Order amends and restates that First Amended and Restated Servicing Agreement between DWR and Utility, approved by the Commission on April 22, 2002, as amended by the Amendment No. 1 to the First Amended and Restated Servicing Agreement, approved by the Commission on July 17, 2002. DWR and Utility are sometimes collectively referred to as the "Parties" and individually referred to as a "Party."

BACKGROUND

A. Under the Act, DWR is authorized to sell electric power and energy to Customers. Amounts payable by DWR under this Servicing Order are payable solely from the Department of Water Resources Electric Power Fund established pursuant to Section 80200 of the California Water Code or other appropriated amounts legally available therefor.

B. Utility is engaged in, among other things, the transmission and distribution of electrical services to customers in its service territory, the billing and collection for electrical services and other charges, and the ownership, installation and reading of electrical meters for such customers.

C. The Act and Applicable Commission Orders allow DWR and the Utility to enter into contracts under which the Utility provides for the transmission and distribution of all power sold or made available for sale by DWR to Customers, and provides billing, collection and related services, as agent for DWR, on terms and conditions that reasonably compensate Utility for its services.

D. On June 22, 2001, the Parties entered into a Servicing Agreement to set forth the terms under which Utility will provide for the transmission and distribution of DWR Power as well as billing and related services.

E. On September 6, 2001, the Commission approved the Servicing Agreement pursuant to Decision 01-09-013, and ordered certain amendments to the Servicing Agreement as described in Ordering Paragraphs 3, 4 and 5 of such decision.

F. On February 21, 2002, the Commission issued Decision 02-02-051, approving and adopting a Rate Agreement between the Commission and DWR.

G. On April 22, 2002, the Commission approved the First Amended and Restated Servicing Agreement pursuant to Decision 02-04-048, which amended the Servicing Agreement to comply with Commission Decision 01-09-013 and to implement certain provisions of the Rate Agreement.

H. On July 17, 2002, the Commission approved Amendment No. 1 to the First Amended and Restated Servicing Agreement ("Amendment No. 1") pursuant to Decision 02-07-038, which amended the First Amended and Restated Servicing Agreement in order to provide for a separate line item on the Consolidated Utility Bills for Bond Charges and to implement the 2002 20/20 Program as ordered by the Commission pursuant to Resolution E-3770.

I. On September 19, 2002, the Commission issued Decision 02-09-053 relating to the allocation of DWR's power contracts, ordering the Parties to modify the Agreement to reflect the new operational arrangements under the contract allocation ordered by the Commission in such decision.

J. This Servicing Order is the result of a desire to comply with Decision 02-09-053 and to incorporate the changes set forth in Amendment No. 1.

NOW, THEREFORE, DWR agrees, and SDG&E is ordered to do as follows:

I. Definitions.

The following terms, when used herein (and in the attachments hereto) with initial capitalization, shall have the meaning specified in this Section 1. Certain additional terms are defined in the attachments hereto. The singular shall include the plural and the masculine shall include the feminine and neuter, and *vice versa*. "Includes" or "including" shall mean "including without limitation." References to a section or attachment shall mean a section or attachment of this Servicing Order, as the case may be, unless the context requires otherwise, and reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made (except as otherwise specifically provided herein). Unless the context otherwise requires, references to Applicable Laws or Applicable Tariffs shall be deemed references to such laws or tariffs as they may be amended, replaced or restated from time to tim e. References to the time of day shall be deemed references to such time as measured by prevailing Pacific time.

A. ACH -- Automated Clearing House, a nationwide payment and collection system which provides for the electronic distribution and settlement of funds.
B. Act -- Chapter 4 of Statutes of 2001 (Assembly Bill 1 of the First 2001-02 Extraordinary Session) of the State of California.
C. Additional Charges -- Additional Charges shall have the meaning set forth in Section 7.2 below.

1.3.5. Aggregate Power--DWR Power, Utility-Provided Electric Power, and, subject to Section 4.3 of the Rate Agreement, ESP Power or other third party provided power for Customers located within the Utility's service territory, to the extent DWR Charges are authorized to be imposed on any such power by Applicable Commission Orders.

D. Allocated Contracts -- The long-term power purchase agreements, listed on Schedule 1 of the Operating Order, allocated to Utility under the Contract Allocation Order.
E. Applicable Commission Orders--Such rules, regulations, decisions, opinions or orders as the Commission may lawfully issue or promulgate from time to time, which further define the rights and obligations of the Parties under this Servicing Order.
F. Applicable Law--The Act, Applicable Commission Orders and any other applicable statute, constitutional provision, rule, regulation, ordinance, order, decision or code of a Governmental Authority.
G. Applicable Tariffs--Utility's tariffs, including all rules, rates, schedules and preliminary statements, governing electric energy service to Customers in Utility's service territory, as filed with and approved by the Commission and, if applicable, the Federal Energy Regulatory Commission.
H. Assign(s)--Assign(s) shall have the meaning set forth in Section 14.3(c).
I. Billing Services--means Consolidated Utility Billing Service

1.9.3 Bond Charges--Bond Charges shall have the meaning set forth in the Rate Agreement.

1.9.7 Bundled Customer--A Customer that purchases electric energy from Utility.

J. Bureau --Bureau shall have the meaning set forth in Section 8.2(b).
K. Business Days-- Regular Monday through Friday weekdays which are customary working days, excluding holidays, as established by Applicable Tariffs.
L. Business Hours -- The period on a Business Day from 9:00 a.m. until 5:00 p.m.
M. C.E.R.S. -- California Energy Resource Scheduling, a division of DWR.
N. Charges -- DWR Charges and Utility Charges.
O. Claims -- Claims shall have the meaning set forth in Section 12.
P. Commission -- The California Public Utilities Commission.
Q. Confidential Information -- Confidential Information shall have the meaning set forth in Section 6.1(c).
R. Consolidated Utility Billing Service -- Billing service through the use of Consolidated Utility Bills as described in Service Attachment 1 to this Servicing Order.
S. Consolidated Utility Bill -- A consolidated bill prepared and presented by Utility to a Customer which includes both the Customer's Utility Charges and DWR Charges.

1.19.3. Contract Allocation Order -- Decision 02-09-053 of the Commission, issued on September 19, 2002, as such Decision may be amended or supplemented from time to time by the Commission.

1.19.7. Contracts -- The Allocated Contracts.

T. Customer -- A customer in Utility's service area that purchases (or is deemed to purchase) Aggregate Power.
U. Daily Remittance Amount -- Daily Remittance Amount shall have the meaning set forth in Section 4.2(a).
V. Daily Remittance Report -- Daily Remittance Report shall have the meaning set forth in Section 4.2(b).
W. Day-Ahead Market -- The daily ISO forward market for which energy and ancillary services are scheduled for delivery on the following calendar day.
X. Delinquent Payment -- Delinquent Payment shall mean the payment of any amount due under this Servicing Order after the time when payment is required to be made hereunder, as further described and/or limited hereunder.
Y. Discloser -- Discloser shall have the meaning set forth in Section 6.1(c).
Z. Reserved.
AA. Reserved.
AB. DWR Charges -- Bond Charges, Power Charges and any other amounts authorized to be collected from Customers pursuant to Applicable Commission Orders and Applicable Law in order to meet DWR's revenue requirements under the Act, as calculated pursuant to this Agreement and Applicable Law.
AC. DWR Power -- The electric power and energy, including but not limited to capacity and output, or any of them supplied by DWR to Bundled Customers pursuant to the Act and Applicable Commission Orders.
AD. DWR Revenues -- Those amounts required to be remitted to DWR by Utility for DWR Charges and DWR Surplus Energy Sales Revenues.

1.30.5. DWR Surplus Energy Sales Revenues -- Revenues received by Utility for the sale of surplus Power to third parties that Utility is required to remit to DWR, consistent with the Contract Allocation Order and Exhibit C of the Operating Order.

AE. DWR's Agent -- DWR's Agent shall have the meaning set forth in Section 8.2(b).
AF. Effective Date -- The date this Servicing Order is effective in accordance with Section 14.16, as such date is set forth on the cover page hereof.

1.32.3 Electric Service Provider -- Electric Service Provider has the meaning set forth in the Rate Agreement.

1.32.7. ESP Power -- electric power sold by an Electric Service Provider to Customers.

AG. Event of Default -- Event of Default shall have the meaning set forth in Section 5.2.
AH. Execution Date -- The date this Servicing Order is fully executed by the Parties, as such date is set forth on the cover page hereof.

1.34.5 Exit Fee -- Any fee that DWR is entitled, under Applicable Law, to assess and collect from a Customer in the event such Customer ceases purchasing DWR Power.

AI. Final Hour-Ahead Schedule -- The final schedule of DWR Power submitted by DWR and Utility and published by the ISO for the Hour-Ahead Market.
AJ. Fund -- Fund shall have the meaning set forth in Section 13.2.
AK. Governmental Authority -- Any nation or government, any state or other political subdivision thereof, and any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to a government, including the Commission.
AL. Governmental Program - Any program or directive established by Applicable Law which directly or indirectly affects the rights or obligations of the Parties under this Servicing Order and which obligates or authorizes DWR to make payments or give credits to Customers or other third parties under such programs or directives.
AM. Hour-Ahead Market -- The ISO forward market for which energy and ancillary services are scheduled for subsequent hours for delivery on the current calendar day.
AN. Imbalance Energy -- The difference between electric power metered and the electric power scheduled in the Day-Ahead Market or Hour-Ahead Market.
AO. Indemnified Party -- Indemnified Party shall have the meaning set forth in Section 12.
AP. Indemnifying Party -- Indemnifying Party shall have the meaning set forth in Section 12.
AQ. Initial Remittance Date -- Initial Remittance Date shall have the meaning set forth in Section 4.2(a).
AR. Insolvency Event -- With respect to Utility, (a) the filing of a decree or order for relief by a court having jurisdiction in its premises or any substantial part of its property in an involuntary case under any applicable federal or state bankruptcy, insolvency or other similar law now or hereafter in effect, or the appointment of a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official for it or for any substantial part of its property, or the ordering of the winding-up or liquidation of its affairs, and such decree or order shall remain unstayed and in effect for a period of 60 consecutive calendar days; or (b) the commencement by it of a voluntary case under any applicable federal or state bankruptcy, insolvency or other similar law now or hereafter in effect, or the consent by it to the entry of an order for relief in an involuntary case under any such law, or the consent by it to the appointment of or taking possession by a receiver, liquidator, assignee, cus todian, trustee, sequestrator or similar official for it or for any substantial part of its property, or the making by it of any general assignment for the benefit of creditors, or the taking of action by it in furtherance of any of the foregoing.
AS. ISO -- The State of California Independent System Operator Corporation.
AT. Late Payment Rate -- The Prime Rate plus 3%.

1.46.1. Operating Order -- The Operating Order between DWR and Utility, dated as of [ ] and approved by the Commission on [ ].

1.46.2. Operating Order Effective Date -- The date the Operating Order is effective in accordance with the provisions thereof.

1.46.3. Power -- Electric power and energy, including but not limited to capacity and output.

1.46.5 Power Charges -- Power Charges shall have the meaning set forth in the Rate Agreement.

AU. Prime Rate -- The rate which Morgan Guaranty Trust Company of New York announces from time to time in New York, New York as its prime lending rate, the Prime Rate to change when and as such prime lending rate changes. The Prime Rate is a reference rate and does not necessarily represent the lowest or best rate actually charged to any customer.

1.47.5 Rate Agreement -- The Rate Agreement between DWR and the Commission adopted by the Commission on February 21, 2002 pursuant to Commission Decision 02-02-051, as the same may be amended and adopted by subsequent Commission proceedings.

AV. Recipient -- Recipient shall have the meaning set forth in Section 6.1(c).
AW. Recurring Fees -- Recurring Fees shall have the meaning set forth in Section 7.1.
AX. Remittance -- A payment by Utility to DWR or its Assign(s) in accordance with this Servicing Order.
AY. Scheduled Energy -- DWR Power set forth on schedules submitted by DWR to Utility and the ISO, or by Utility to the ISO, as the case may be, in the Day-Ahead Market and Hour-Ahead Market that, pursuant to Section 2.2(b), DWR provided to Bundled Customers.
AZ. Scheduling Coordinator -- to -- Scheduling Coordinator Trade -- Schedules for energy transferred from one ISO scheduling coordinator to another. Such schedules are deemed delivered by the ISO upon publication by the ISO of the final schedules.
BA. Services -- Billing Services, metering services and meter reading services which may be performed by Utility and related collection, remittance and other services provided by Utility for DWR pursuant to this Servicing Order.

1.53.5 Servicing Order -- This 2003 Servicing Order, including all attachments hereto.

BB. State -- The State of California.
BC. Set-Up Fee -- Set-Up Fee shall have the meaning set forth in Section 7.1.
BD. Term -- The term of this Servicing Order as set forth in Section 5.1.

BE. 20/20 Program -- 20/20 Program shall have the meaning set forth in Section 4.3.
BF. Utility Charges -- Charges incurred by a Customer for electricity-related services and products provided by Utility to the Customer, as approved by the Commission and, as applicable, the Federal Energy Regulatory Commission or other Governmental Authority (including, but not limited to, any Competition Transition Charges or Fixed Transition Amount Charges owing to Utility or its affiliates, as those terms are defined under the California Public Utilities Code). Utility Charges shall not include DWR Charges or charges related to natural gas related services and products.
BG. Utility-Provided Electric Power -- Utility-Provided Electric Power shall refer to electricity from Utility's own generation, qualifying facility contracts, other power purchase agreements and bilateral contracts. Utility-Provided Electric Power shall include neither DWR Power nor ESP Power.

The terms used in the attachments, but not specifically defined herein or elsewhere in this Agreement, are understood by the Parties to have their ordinary meanings.

II. Energy Delivery, Surplus Energy Sales and Ownership.

A. Delivery of DWR Power.

Pursuant to the Act and Applicable Commission Orders, Utility is ordered to transmit, or provide for the transmission of, and distribute DWR Power to Bundled Customers over Utility's transmission and distribution system in accordance with Applicable Law, Applicable Tariffs and any other agreements between the Parties.

B. Data and Information Communications Procedures.

a. Utility shall estimate Bundled Customer usage and Utility-retained generation for a given trade day and shall communicate the net of such estimate to DWR by 7:00 a.m. on the preceding Business Day; provided, however upon the Operating Order Effective Date, Utility is directed to comply with the data and information communications procedures of the Operating Order. In the event that DWR observes a persistent deviation between estimated Bundled Customer usage and actual Bundled Customer usage, or between estimated Utility-retained generation and actual Utility-retained generation, DWR may request Utility to review, and Utility will promptly commence to review, Utility's forecast methodology and will report the results of such review to DWR; provided, however, that Utility shall have no obligation to correct or minimize such deviation except as provided in Attachment H hereto.
b. DWR agrees to send to Utility in writing each day the Scheduling Coordinator-to-Scheduling Coordinator Trade between DWR and Utility. This information shall be delivered no later than 9:30 a.m. for trades in the Day-Ahead Market for the following day, and no later than two hours and twenty minutes prior to the start of the delivery hour for trades in the Hour-Ahead Market. Utility is ordered and DWR agrees to separately provide these schedules to the ISO prior to the close of the respective markets. The above deadlines for DWR are set because the ISO Day-Ahead Market currently closes at 10:00 a.m. on the day before delivery and the ISO Hour-Ahead Market currently closes two hours before the delivery hour. If these closing times should change, the deadlines for submission of DWR data to Utility shall change proportionately, which revised deadlines shall be confirmed in writing by DWR and Utility. DWR agrees that, upon Utility's request, DWR shall supply information to Utility substantiating to Utility's reasonable satisfaction (i) the total amount of energy purchased by DWR in the Day-Ahead Market and Hour-Ahead Market; and (ii) other such information that may be required for Utility to verify the DWR Charges, or any component thereof, including information regarding the allocation of such energy among Customers and other third parties to the extent so required. Notwithstanding the provisions of this paragraph (b), upon the Operating Order Effective Date, Utility shall schedule and dispatch Power as provided in the Operating Order.
c. The basis for remittances of revenues for Power Charges shall be the amounts collected from Bundled Customers for delivery of DWR Power, as further described in Attachments B and H of this Servicing Order, and upon the Operating Order Effective Date, consistent with the principles set forth in Exhibit C of the Operating Order. The basis for the remittance of revenues for Bond Charges shall be amounts collected from Customers pursuant to future Applicable Commission Orders implementing such Bond Charges (including, without limitation, the portion of any Exit Fee imposed by the Commission on Customers of Electric Service Providers or upon any other third party which constitutes a Bond Charge). If and when ordered by the Commission, the remaining portion of any such Exit Fee shall be remitted to DWR in a manner reasonably agreed upon by the Parties. All DWR Charges shall be at the applicable Commission-approved rates. If either Party obtains actual knowledge of a material flaw in the procedures or method s set forth in this Servicing Order, and such flaw has a material adverse effect on (i) the delivery of Services (including, without limitation, the timely and accurate remittance of DWR Charges and DWR Surplus Energy Sales Revenues to DWR), or (ii) the timely and accurate payment to Utility of compensation for Services hereunder, the discovering Party shall bring such flaw to the attention of the other Party within a reasonable time. Upon the delivery of such notice, the Parties shall conduct good faith negotiations to resolve such flaw. Without limiting any other terms, express or implied, of this Servicing Order or any other agreement between the Parties, the Parties acknowledge that the two preceding sentences do not impose an independent obligation to perform any investigation or monitoring to discover any such flaw.
d. Adjustments to the remittance of revenues to DWR prior to the Operating Order Effective Date in (c) above will be based on the following, (i) the difference between scheduled quantities and those scheduled quantities which are actually reflected in ISO settlement statements, and (ii) the difference between the Utility estimate of Customer usage and the actual Customer usage reflected in ISO settlement statements. Adjustments to the remittance of revenues to DWR after the Operating Order Effective Date in (c) above will be based on the following, (i) the difference between estimated dispatched quantities of Utility and DWR Contracts and the actual dispatched quantities reflected in ISO settlement statements, and (iii) the difference between Utility's estimate of Customer usage and the actual Customer usage reflected in ISO settlement statements. Utility shall include an adjustment of DWR Charges, DWR Power, Utility-Provided Electric Power, DWR Surplus Energy Sales Revenues and, as applicable, ESP Power, on its next Consolidated Utility Bill if so provided for in Attachment H.
e. Upon the Operating Order Effective Date, Utility shall calculate and remit DWR Surplus Energy Sales Revenues consistent with the Contract Allocation Order and the Operating Order. The basis for remittance of DWR Surplus Energy Sales Revenues shall be amounts collected by Utility from third parties for sales of surplus Power, as further described in Exhibit C of the Operating Order, all in accordance with the Contract Allocation Order.
f. All data and information to be exchanged between the Parties in connection with scheduling or settlement of transactions shall be in the format agreed to by Utility and DWR and shall, except as otherwise provided by this Servicing Order or Utility Applicable Tariffs, or as may be approved by Utility in its reasonable discretion, be submitted electronically. If a Party receives any information that is unreadable, or contains data that cannot be processed by the receiving Party's system, or is otherwise damaged, such receiving Party shall inform the sending Party of such problem. Until any such problem is corrected, the receiving Party shall not be responsible for processing information received in this condition. The foregoing notwithstanding, a receiving Party shall not be excused from its obligation to process information if the receiving Party cannot read or otherwise process the information sent by the sending Party as a result of defects, errors, bugs, or viruses in the receiving Party's systems o r software or due to negligence or wrongful act(s) or failure(s) to act on the part of the receiving Party's employees, agents, independent contractors, subcontractors or assigns.

C. Ownership of DWR Power, Surplus Power, Utility-Provided Electric Power and DWR Revenues.

(a) Notwithstanding any other provision herein, and in accordance with the Act and Section 80110 of the California Water Code, DWR shall retain title to all DWR Power sold by DWR to Bundled Customers or any surplus Power sold by Utility on DWR's behalf in accordance with the terms of the Operating Order and consistent with the Contract Allocation Order. In accordance with the terms hereof and the Operating Order, as the case may be, Utility is acting solely as the servicing agent for DWR with respect to the sale of Aggregate Power provided to Customers and with respect to sales of surplus Power to third-party power purchasers. In accordance with the Act and Section 80104 of the California Water Code, upon the delivery of DWR Power to Bundled Customers or the sale of surplus Power to third-party power purchasers, those Bundled Customers and third-party power purchasers, shall be deemed to have purchased that Power from DWR, and payment for any such sale shall be a direct obligation of such Bundled Cu stomers or third-party purchasers, as the case may be, to DWR. Notwithstanding any other provision herein, Utility shall retain title to all Utility-Provided Electric Power supplied by Utility to Bundled Customers and all surplus Power provided by Utility.

(b) DWR Charges and DWR Surplus Energy Sales Revenues shall be the property of DWR for all purposes.

D. Allocation of DWR Power and DWR Surplus Energy Sales Revenues.

DWR Power will be allocated pursuant to the Act and other Applicable Law and Applicable Tariffs. Upon the Operating Order Effective Date, DWR Power and DWR Surplus Energy Sales Revenues shall be allocated consistent with the Contract Allocation Order, and as provided in the Operating Order and this Servicing Order.

5. DWR Surplus Energy Sales Revenues.

The treatment of surplus Power shall be governed by the Contract Allocation Order and as further provided by Operating Order, as the same may be hereafter amended by written agreement of the Parties.

I. Billing Services.

A. Provision of Services by Utility.

a. Utility shall provide metering services, meter reading services and Billing Services relating to (i) the delivery of DWR Power that is the basis for a Power Charge and (ii) the delivery of Aggregate Power, except to the extent that such services are provided by a third party, that is the basis for a Bond Charge. In the event that billing services are provided by a third party to its Customers, Utility shall bill and collect DWR Charges from the third party supplier, as applicable to the third party for its Customers, on behalf of DWR, in accordance with Applicable Commission Orders and Applicable Tariffs and remit the same to DWR upon collection. Utility provided metering services, meter reading services and Billing Services shall be provided in accordance with Applicable Commission Orders, Applicable Tariffs and Service Attachment 1 hereto.

Upon the Operating Order Effective Date, Utility shall sell surplus Power on behalf of DWR, and provide invoicing and collection of amounts owed by third parties for such surplus Power sales made by Utility on DWR's behalf and allocate such revenues to DWR. Surplus Power sales made by Utility on DWR's behalf, including the invoicing and collection of amounts owed by third parties and credit risk management, shall be conducted by Utility in accordance with Applicable Commission Orders, including but not limited to, the Contract Allocation Order, Applicable Tariffs, the Operating Order and Service Attachment 2 hereto.

b. On behalf of DWR, Utility shall (i) follow its customary standards, policies and procedures in performing its duties hereunder and (ii) perform its duties hereunder using the same degree of care and diligence that Utility exercises for its own account.

c. For surplus Power sales to third parties, Utility shall apply prudent credit risk management criteria to ensure that such purchasers meet or exceed DWR credit criteria, or in the absence of such DWR designated criteria, then consistent with industry accepted credit standards. If Utility sells surplus Power to an entity that requires collateral, the cost and obligation to post such collateral shall be Utility's responsibility.
d. Utility shall be responsible for all transaction fees or other costs associated with the sale of surplus Power imposed by third-party purchasers or any agents of Utility or such purchaser.

A. Reserved.

B. Modification of Billing and Metering Systems.

Utility shall have the right to modify and replace its billing and metering systems, subject to the requirements of Applicable Law, if any. However, to the extent that such modifications and replacements materially interrupt Services provided by Utility to DWR, Utility shall provide to DWR, as soon as reasonably practicable, prior written notice of any such changes, including, but not limited to, such changes as are required by Applicable Law or Applicable Commission Order(s). Moreover, to the extent any such modifications would affect the collection of DWR Charges or DWR Surplus Energy Sales Revenues in a manner which is different from the collection of Utility Charges or other Utility revenues from the sale of Power, Utility shall obtain DWR's prior written consent to such modifications, which consent shall not be unreasonably withheld or delayed.

C. Customer Inquiries.

So long as Consolidated Utility Billing Service is in place, Utility shall address all Customer inquiries regarding the DWR Charges. DWR agrees to provide all necessary information to Utility in order to permit Utility to respond to all Customer inquiries on a timely basis. In extraordinary circumstances, Utility will refer Customer inquiries to DWR in a manner to be agreed upon by the Parties. In the event that either (i) DWR's failure to provide all such necessary information to Utility, (ii) DWR's provision of inaccurate information or (iii) DWR's failure to handle Customer inquiries referred to it by Utility in extraordinary circumstances in the manner agreed upon by the Parties results in Utility's non-compliance with its obligations under this Section 3.4, such non-compliance will not constitute a material breach of this Servicing Order and will not give DWR the right to terminate this Servicing Order.

5. Inquiries From Third-Party Power Purchasers.

So long as Utility, as agent to DWR, sells surplus Power to third-party purchasers, Utility shall address all third-party purchasers' inquiries regarding such surplus Power sales. If Utility and any third-party purchaser should have a dispute with respect to the sale of surplus Power, Utility shall resolve all such disputes. Utility shall apply the same practices to the resolution of such disputes as Utility uses to resolve disputes related to any other transaction with such third-party purchaser.

I. DWR Revenues; Remittance of DWR Revenues.

A. DWR Revenues.

DWR Revenues required to be remitted to DWR under this Servicing Order shall be based upon DWR Charges in effect from time to time pursuant to Applicable Law and Attachments B and H hereto. Upon the Operating Order Effective Date, DWR Surplus Energy Sales Revenues shall be remitted based upon the principles provided in Exhibit C of the Operating Order.

B. Remittance of DWR Revenues.

As provided below and in Attachments B, H and J hereto, all DWR Revenues shall be held by Utility in trust for DWR (whether or not held together with other monies) and shall be remitted to DWR.

a. Within one Business Day after the Effective Date, Utility shall determine the Daily Remittance Amount in the manner set forth in Attachment B hereto (the "Daily Remittance Amount"). On the day of such determination (the "Initial Remittance Date"), Utility shall remit to DWR or its Assign(s) the Daily Remittance Amount, if any, for each day from the Effective Date up to and including the Initial Remittance Date. On each subsequent Business Day during the remainder of the Term, Utility shall determine and remit to DWR or its Assign(s) the Daily Remittance Amount for such Business Day. If the Utility determines that it has remitted amounts to DWR in error, Utility may provide notice of such event to DWR (accompanied by an explanation of the facts surrounding such erroneous deposit), and DWR agrees to review such notice and information as soon as practicable and promptly repay such funds if and to the extent DWR agrees with Utility, such agreement not to be unreasonably withheld or delayed.
b. Each Remittance shall be accompanied by a written report substantially in the form of that set forth in Attachment C hereto (the "Daily Remittance Report"). Utility will not be required at any time to advance or pay any of its own funds in the fulfillment of its responsibilities hereunder with respect to DWR Charges, except to the extent provided otherwise in the Attachments hereto.
c. Utility, from time to time, will make adjustments regarding amounts remitted as described in Attachment B hereto. In addition, monthly reconciliation reports, as described in Attachment C hereto, shall be filed with DWR by Utility.
d. Except as expressly provided in this Servicing Order (including the Attachments hereto), Utility shall not deduct from amounts due to DWR hereunder any amounts owing by DWR to Utility which relate to arrangements within or outside the scope of this Servicing Order, or any other amounts, and Utility expressly waives any right to do so. The foregoing shall not limit Utility's rights to seek any other remedies permitted under other arrangements with DWR.
e. The Parties recognize that prior to October 1, 2001, Utility has been remitting DWR Charges to DWR based upon the interim remittance methodologies described in Decision 01-03-081, adopted by the Commission on March 27, 2001, and Decision 01-05-064, adopted by the Commission on May 15, 2001 (collectively the "Interim Remittance Methodologies"). Utility shall reconcile the amounts remitted pursuant to the Interim Remittance Methodologies at the time and in the manner set forth in Attachment B hereto.

   Beginning October 1, 2001, Utility has also made Remittances utilizing the method set forth in Section 2.2 and Attachments B and H of the Servicing Agreement approved by the Commission pursuant to Decision 01-09-013, as amended from time to time. On and after the Operating Order Effective Date, Utility shall transition to using the Post-Transition Remittance Methodology as provided in Attachment H hereto and consistent with the Settlement Principles for Remittances and Surplus Revenues set forth in Exhibit C of the Operating Order, this Servicing Order and Attachments B and H hereto.

f. Upon the Operating Order Effective Date, the percentage of surplus Power sales which is to be allocated to DWR by Utility shall be determined consistent with the Contract Allocation Order and the principles set forth on Exhibit C of the Operating Order, all as further provided in this Servicing Order.
g. Following the Operating Order Effective Date, Utility shall calculate and remit to DWR the Surplus Energy Sales Revenues Remittance Amount as provided for in Exhibit C (Settlement Principles For Remittances And Surplus Revenues) of the Operating Order. Each Monthly Remittance Amount for surplus Power sold on behalf of DWR shall be accompanied by a written report in a form to be developed by the Parties.

C. 20/20 Program.

To the extent that the program established in the California Governor's Executive Order D-30-01, dated March 13, 2001, and Executive Order D-33-01, dated April 26, 2001, as the foregoing orders may be amended, supplemented, extended or otherwise modified (the "20/20 Program"), obligates DWR to make payments or extend credits to Bundled Customers or other third parties under such program, Remittances to DWR may be reduced by such payments to the extent of DWR's responsibility as required by Applicable Law and Applicable Tariffs. DWR agrees that Utility's reasonable initial implementation and recurring administrative costs associated with such program shall be paid by DWR in the same manner and at the same times as Utility's Set-Up Fee and Recurring Fees, respectively, as described in Sections 7.2 and 7.3 below. Additionally, Utility will invoice DWR for any other costs incurred by Utility under such program, and DWR agrees to pay such invoices as Additional Charges, in the manner contemplated i n Section 7 below. The method for calculating reduced Remittances to DWR under this Section 4.3, as well as Utility's implementation and administration costs, shall be as set forth in Attachment F hereto.

II. Term and Termination; Events of Default.

A. Term.

The term of this Servicing Order (the "Term") shall commence on the Effective Date and shall terminate on the earlier of (a) 180 calendar days after the last date DWR Charges are imposed on Customers and 180 calendar days after the last date Utility sells surplus Power on behalf of DWR pursuant to the Operating Order, or (b) the earlier termination of this Servicing Order pursuant to this Section 5.

B. Events of Default by Utility.

The following events shall constitute "Events of Default" by Utility under this Servicing Order:

a. any failure by Utility to remit to DWR or its Assign(s) any required Remittance in the manner and at the time specified in this Servicing Order (except to the extent otherwise allowed under Sections 4.3 and 7.2) that continues unremedied for three Business Days after the earlier of the day Utility receives written notice thereof from DWR or the day the responsible manager at Utility first has actual knowledge of such failure; or
b. any failure by Utility to duly observe or perform in any material respect any other term or condition of Utility set forth in this Servicing Order, which failure (i) materially and adversely affects the interests or rights of DWR or its Assign(s), and (ii) continues unremedied for a period of 60 calendar days after written notice of such failure has been given to Utility by DWR or its Assign(s); or
c. any representation or warranty made by Utility in this Servicing Order proves to have been incorrect when made, which has a material adverse effect on DWR or its Assign(s) and which material adverse effect continues unremedied for a period of 60 calendar days after the date on which written notice thereof has been given to Utility by DWR or its Assign(s).

C. Consequences of Utility Events of Default.

a. Upon any Event of Default by Utility, DWR may, in addition to exercising any other remedies available under this Servicing Order or under Applicable Law, (i) terminate this Servicing Order in whole or in part (including Service Attachment 1); and (ii) apply to the Commission and, if necessary, any court of competent jurisdiction for sequestration and payment to DWR or its Assign(s) of DWR Revenues. Remittances not made to DWR by Utility on the date due (except to the extent Remittances were not made by operation of Sections 4.3, 7.2, 14.4 or Attachment B hereto) shall bear interest at the Prime Rate from the first day after the due date until the third Business Day after the due date, and at the Late Payment Rate thereafter until paid.
b. Reserved.

D. Defaults by DWR.

DWR agrees that it shall be in default under this Servicing Order upon:

a. subject to subsections (b), (c), (d) and (e) below, DWR's failure to cure its material breach of any provision of this Servicing Order within 60 calendar days after receiving written notice thereof from Utility;
b. Except for amounts to which DWR has objected in writing pursuant to Section 7.2, DWR's failure to pay to Utility the Set-Up Fee or Recurring Fees within three Business Days after the date they are due hereunder, as provided in Section 7;
c. Except for amounts to which DWR has objected in writing pursuant to Section 7.2, DWR's failure to pay to Utility the initial implementation and recurring administrative costs associated with Utility's implementation of the 20/20 Program, as provided in Section 4.3;
d. Except for amounts to which DWR has objected in writing pursuant to Section 7.2, DWR's failure to fulfill any other monetary obligation hereunder within 15 calendar days after receiving written notice from Utility that such obligation is past due; or
e. DWR's failure to fulfill the terms and obligations under Section 2.2 within 15 calendar days after receiving written notice thereof from Utility.

Upon any default by DWR under this Section 5.4, Utility may exercise any remedies available under this Servicing Order or under Applicable Law, provided that Utility shall have no right to terminate this Servicing Order either in whole or in part (including Service Attachment 1) or any obligation hereunder. DWR agrees that, except for amounts to which DWR has objected in writing pursuant to Section 7.2 and which are determined not to be owed, any Set-Up Fee or Recurring Fees, or any initial implementation and recurring administrative costs associated with Utility's implementation of the 20/20 Program, as provided in Section 4.3, which are not paid to Utility on the date due shall bear interest at the Prime Rate from the first day after the due date until the third Business Day after the date they are required to be made hereunder, and at the Late Payment Rate thereafter until paid. DWR further agrees that, except for amounts to which DWR has objected in writing pursuant to Section 7.2 and which are determined not to be owed, any other monetary obligation payable to Utility by DWR shall bear interest at the Prime Rate from the date due until 15 days after receiving written notice from Utility that such amount is overdue, and thereafter at the Late Payment Rate. DWR further agrees that, when and to the extent that any amounts to which DWR has objected in writing pursuant to Section 7.2 are determined to be owing, such amounts shall bear interest from the due date at the rates described above for the applicable category of obligation.

E. Survival of Payment Obligations.

Upon termination of this Servicing Order, DWR agrees that it, and it is ordered that SDG&E, shall remain liable to the other Party for all amounts owing under this Servicing Order. Utility shall continue to collect and remit, pursuant to the terms of this Servicing Order, Attachment B and Attachment J hereto, any DWR Charges billed to Customers before the effective date of termination and DWR Surplus Energy Sales Revenues attributable to surplus Power sales made prior to the effective date of termination, except as provided in Attachment B hereto.

III. Confidentiality.

A. Proprietary Information.

a. Nothing in this Servicing Order shall affect Utility's obligations to observe any Applicable Law prohibiting the disclosure of Confidential Information regarding its Customers.
b. Nothing in this Servicing Order, and in particular nothing in Sections 6.1(e)(x) through 6.1(e)(z) of this Servicing Order, shall affect the rights of the Commission to obtain from Utility, pursuant to Applicable Law, information requested by the Commission, including Confidential Information provided by DWR to Utility. Applicable Law, and not this Servicing Order, will govern what information the Commission may disclose to third parties, subject to any confidentiality agreement between DWR and the Commission.
c. Each Party may acquire information and material that is the other Party's confidential, proprietary or trade secret information. As used herein, "Confidential Information" means any and all technical, commercial, financial and customer information disclosed by one Party to the other (or obtained from one Party's inspection of the other Party's records or documents), including any patents, patent applications, copyrights, trade secrets and proprietary information, techniques, sketches, drawings, maps, reports, specifications, designs, records, data, models, inventions, know-how, processes, apparati, equipment, algorithms, software programs, software source documents, object code, source code, and information related to the current, future and proposed products and services of each of the Parties, and includes, without limitation, the Parties' respective information concerning research, experimental work, development, design details and specifications, engineering, financial information, procurement requi rements, purchasing, manufacturing, business forecasts, sales and merchandising, and marketing plans and information. In all cases, Confidential Information includes proprietary or confidential information of any third party disclosing such information to either Party in the course of such third party's business or relationship with such Party. Utility's Confidential Information also includes any and all lists of Customers, and any and all information about Customers, both individually and aggregated, including but not limited to Customers' names, street addresses of Customer residences and/or facilities, email addresses, identification numbers, Utility account numbers and passwords, payment histories, energy usage, rate schedule history, allocation of energy uses among Customer residences and/or facilities, and usage of DWR Power. DWR agrees, and it is ordered with respect to SDG&E, that all Confidential Information disclosed by the disclosing Party ("Discloser") will be considered Confidential Infor mation by the receiving Party ("Recipient") if identified as confidential and received from Discloser.
d. DWR agrees, and SDG&E is ordered to take all steps reasonably necessary to hold in trust and confidence the other Party's Confidential Information. Without limiting the generality of the immediately preceding sentence, DWR agrees and SDG&E is ordered (i) to hold the other Party's Confidential Information in strict confidence, not to disclose it to third parties or to use it in any way, commercially or otherwise, other than as permitted under this Servicing Order; and (ii) to limit the disclosure of the Confidential Information to those of its employees, agents or directly related subcontractors with a need to know who have been advised of the confidential nature thereof and who have acknowledged their express obligation to maintain such confidentiality.
e. DWR agrees, and it is ordered with respect to SDG&E that the foregoing two paragraphs will not apply to any item of Confidential Information if: (i) it has been published or is otherwise readily available to the public other than by a breach of this Servicing Order; (ii) it has been rightfully received by Recipient from a third party without breach of confidentiality obligations of such third party and outside the context of the provision of Services under this Servicing Order; (iii) it has been

independently developed by Recipient personnel having no access to the Confidential Information; or (iv) it was known to Recipient prior to its first receipt from Discloser. DWR agrees, and it is ordered with respect to SDG&E that, in addition, Recipient may disclose Confidential Information if and to the extent required by law or a Governmental Authority, provided that (x) Recipient shall give Discloser a reasonable opportunity to review and object to the disclosure of such Confiden tial Information, (y) Discloser may seek a protective order or confidential treatment of such Confidential Information, and (z) Recipient shall make commercially reasonable efforts to cooperate with Discloser in seeking such protective order or confidential treatment. DWR agrees, and it is ordered with respect to SDG&E that Discloser shall pay Recipient its reasonable costs of cooperating.

B. No License.

DWR agrees, and it is ordered with respect to SDG&E that nothing contained in this Servicing Order shall be construed as granting to a Party a license, either express or implied, under any patent, copyright, trademark, service mark, trade dress or other intellectual property right, or to any Confidential Information now or hereafter owned, obtained, controlled by, or which is or may be licensable by, the other Party.

C. Survival of Provisions.

DWR agrees, and it is ordered with respect to SDG&E that the provisions of this Section 6 shall survive the termination of this Servicing Order.

IV. Payment of Fees and Charges.

A. Utility Fees.

DWR agrees that it will pay to Utility a fee, calculated in accordance with Attachment G hereto (the "Set-Up Fee"), in order to cover Utility's costs of establishing the procedures, systems, and mechanisms necessary to perform Services. In addition, DWR also agrees to pay to Utility an annual fee, calculated in accordance with Attachment G hereto, payable monthly in arrears as provided in Section 7.2 hereof (the "Recurring Fees") for Services rendered pursuant to Section 3.1, Section 3.4 and Service Attachment 1 to this Servicing Order. Additional fees to cover changes in costs or the costs of other services provided hereunder shall be as set forth in Attachment G, or if not set forth therein, shall be negotiated by the Parties. Except to the extent provided otherwise in subsequent agreements between the Parties and except to the extent otherwise provided under the 20/20 Program, if the Parties are unable to resolve any disputes relating to such additional fees, either Party may, upon giving seven cale ndar days advance written notice to the other, submit the dispute to the Commission for proposed resolution, in accordance with Applicable Law. Provided, however, DWR shall pay to Utility fees that will permit recovery of the Utility's incremental cost of establishing procedures, systems and mechanisms necessary to perform Services in connection with Bond Charges. The Utility shall file these fees with the Commission. DWR, prior to Commission action on this filing, shall pay the fees as filed. Upon final action by the Commission, such payment shall be adjusted to reflect the fees approved by the Commission, together with interest from the date of payment to the date of adjustment, at the Prime Rate. Utility acknowledges that the Commission may adjust, with notice to Utility and an opportunity for Utility to be heard, Utility's rates to avoid double recovery of any costs paid by DWR hereunder which have already been included in Utility's rates.

B. Payment of Utility Fees and Charges.

The Set-Up Fee shall be due and payable on the effective date of the Servicing Agreement approved by the Commission pursuant to Decision 01-09-013, and DWR agrees to pay Utility the Set-Up Fee, in the manner provided in Section 7.3 below. After receipt of Utility's invoice 30 days in advance, DWR agrees to pay to Utility its Recurring Fees in monthly installments by the 10th day of each month in the manner provided in Section 7.3 below. Additionally, with respect to all other fees and charges which are expressly identified as owing by DWR to Utility under this Servicing Order (the "Additional Charges") Utility shall (in paper format or, at DWR's option, electronically) submit to DWR an invoice reflecting such Additional Charges for such calendar month. Any invoiced amount for Recurring Fees or Additional Charges shall be due and payable within three Business Days after presentation, and any invoiced amount and the Set-Up Fee shall be considered past due 30 calendar days after presentation, a fter which interest shall accrue as provided in Section 7.4. To the extent that any invoiced amounts described in this Section 7.2 are not fully paid within 45 days after presentation, and DWR has not objected to Utility in writing by such date, DWR agrees that Utility shall have the right to deduct from any future Remittance(s) the unpaid and overdue amount which is not the subject of any such objection by such date, until such invoice is paid in full or until the dispute over the amount due has been resolved.

C. Method of Payment.

a. Except as otherwise expressly provided herein, DWR agrees, and with respect to SDG&E it is ordered that any payment from either Party to the other Party under this Servicing Order shall be made by ACH or, if ACH is unavailable, then by wire transfer of immediately available funds to the bank account designated by the receiving Party or, if mutually agreed, paid by means of a check or warrant sent to the recipient's address indicated in accordance with Section 14.14 hereof. Where the Parties have made arrangements for a bank or other third party to remit funds from one Party to the other Party, DWR agrees, and with respect to SDG&E it is ordered that proper identification of the bank or third party, including the account number, shall be furnished in writing. DWR agrees, and with respect to SDG&E it is ordered that the remitting Party shall reasonably cooperate in correcting any bank or other third-party errors and shall not be relieved of its payment responsibilities because of such errors.
b. Except as expressly provided otherwise herein or under any Applicable Law, Utility shall be required to pay all expenses incurred by it in connection with its activities under this Servicing Order (including any fees to and disbursements by accountants, counsel, or any other person, any taxes, fees, surcharges or levies imposed on Utility, and any expenses incurred in connection with reports to be provided hereunder) out of the compensation paid to it pursuant to this Section 7, and Utility shall not be entitled to any extra payment or reimbursement therefor. Notwithstanding anything to the contrary above, if and to the extent any additional taxes (excluding taxes on Utility's income), fees or charges are imposed on Utility due solely to Utility's performance of Services hereunder with respect to DWR Charges (such as franchise fees or taxes on DWR Power, the State of California electric energy surcharge, local utility user taxes, or Commission fees), to the extent these taxes, fees, or charges are not already included in Utility's rates and Utility has not been reimbursed therefor and is not authorized to seek reimbursement from Customers therefor, DWR agrees to reimburse Utility therefor as "Additional Charges" in accordance with Section 7.2.

D. Interest

DWR agrees, and with respect to SDG&E it is ordered that except as provided in Sections 5.3, 5.4 or 7.5, any Delinquent Payment under this Servicing Order (whether or not a regularly scheduled payment) shall bear interest at the Late Payment Rate.

7.5. Reconciliation Amounts

If a change in Applicable Law (but only if and to the extent such change is expressly intended to be retroactive in effect) or the discovery of a "Material Flaw" results in a discrepancy between any amount paid hereunder and the amount that would have been paid if the changed Applicable Law had been in effect or the Material Flaw had been corrected, such discrepancy (a "Reconciliation Amount") shall be paid by the party that benefited from the superseded Applicable Law or Material Flaw to the other party. Reconciliation Amounts shall be paid in full within 30 days after receipt of an invoice therefore unless a different payment schedule is mutually agreed upon between the parties. Interest on any Reconciliation Amount shall accrue from the original date on which the incorrect payment or remittance produced by the Material Flaw was due until such Reconciliation Amount is paid. Interest on any Reconciliation Amount shall be calculated on the basis of a 365- or 366- day year, as applicable, for the actual days elapsed. For a Reconciliation Amount due from Utility to DWR, interest shall accrue until the date such Reconciliation Amount is due at the rate defined in Utility's Preliminary Statement, II. Balancing Accounts, Section K, Purchased Electric Commodity Account (PECA), subsection 4(i), or superceding account then in effect. For a Reconciliation Amount due from DWR to Utility, interest shall accrue until the date such Reconciliation Amount is due at the State's Pooled Money Investment Account Rate in effect from time to time. If an outstanding Reconciliation Amount is not paid in full when due, any overdue amounts shall be considered Delinquent Payments and interest shall accrue at the Late Payment Rate from the date such overdue amount was due until paid, in accordance with Section 7.4.

For purposes of this Section, a "Material Flaw" is a procedure or method set forth in this Agreement, or an aspect thereof, which results in the payment or remittance of amounts to either Party (or the failure so to remit or pay) in a time, manner or amount that is inconsistent with Applicable Law. It is expressly agreed and understood that the undercollection or overcollection of amounts required to be collected under Section 80134 of the California Water Code due to incorrect projections of DWR's revenue requirements or due to incorrect projections in the setting of DWR Charges shall not constitute a Material Flaw and are intended to be trued-up in subsequent revenue requirements.

V. Records; Audit Rights; Annual Certification.

A. Records.

Utility shall maintain accurate records and accounts relating to DWR Revenues (including separate accounting of Bond Charges and Power Charges) in sufficient detail to permit recordation of DWR Charges billed to Customers and DWR Revenues remitted by Utility to DWR. Utility shall maintain accurate records and accounts relating to DWR Surplus Energy Sales Revenues (including separate accounting of surplus Power sales transactions by counterparty) in sufficient detail to permit recordation of DWR Surplus Energy Sales Revenues separate from other DWR Revenues remitted by Utility to DWR. Utility shall provide to DWR and its Assign(s) access to such records. Access shall be afforded without charge, upon reasonable request made pursuant to Section 8.2. DWR agrees that access shall be afforded only during Business Hours and in such a manner so as not to interfere unreasonably with Utility's normal operations. Utility shall not treat DWR Revenues as income or assets of the Utility or any affiliate for any ta x, financial reporting or regulatory purposes, and the financial books or records of Utility and affiliates shall be maintained in a manner consistent with the absolute ownership of DWR Revenues by DWR and Utility's holding of DWR Revenues in trust for DWR (whether or not held together with other monies).

B. Audit Rights.

a. Upon 30 calendar days' prior written notice, DWR may request an audit, conducted by DWR or its agents (at, DWR agrees, DWR's expense), of Utility's records and procedures, which shall be limited to records and procedures containing information bearing upon: (i) DWR Charges being billed to Customers by Utility (and Customer payments of DWR Charges); (ii) fees to Utility for Services provided by Utility pursuant to this Servicing Order; (iii) Utility's performance of its obligations under this Servicing Order; (iv) allocation of Aggregate Power that is subject to DWR Charges pursuant hereto or Applicable Law; (v) projection or calculation of DWR's revenue requirements as described in Sections 80110 and 80134 of the California Water Code from time to time; (vi) DWR Surplus Energy Sales Revenues collected from third-party purchasers and the collection and allocation of such revenues, and (vii) such other matters as may be permitted by Applicable Commission Orders, Applicable Tariffs or as DWR or its Assign(s) may reasonably request. The audit shall be conducted during Business Hours without interference with Utility's normal operations, and in compliance with Utility's security procedures.
b. As provided in the Act, the State of California Bureau of State Audits (the "Bureau") shall conduct a financial and performance audit of DWR's implementation of Division 27 (commencing with Section 80000) of the California Water Code, such audit to be completed prior to December 31, 2001, and the Bureau shall issue a final report on or before March 31, 2003. In addition, as provided in Section 8546.7 of the California Government Code, pursuant to this Section 8.2, Utility is ordered to permit DWR or the State of California Department of General Services, the Bureau, or their designated representative ("DWR's Agent") to review and to copy (at, DWR agrees, DWR's expense) any non-confidential records and supporting documentation pertaining to the performance of this Servicing Order and to conduct an on-site review of any Confidential Information pursuant to Sections 8.3 and 8.8 hereof. Utility shall maintain such records for such possible audit for three years after final Remittance to DWR. Utility shall allow such auditor(s) access to such records during Business Hours and to allow interviews of any employees who might reasonably have information related to such records. Further, Utility shall include a similar right for DWR or DWR's Agent to audit records and interview staff in any contract between Utility and a subcontractor related to performance of this Servicing Order.

C. Confidentiality.

Materials reviewed by either Party or its agents in the course of an audit may contain Confidential Information subject to Section 6 above. DWR agrees, and with respect to SDG&E it is ordered that the use of all materials provided to DWR or Utility or their agents, as the case may be pursuant to this Section 8, shall comply with the provisions in Section 6 and shall be limited to use in conjunction with the conduct of the audit and preparation of a report for appropriate distribution of the results of the audit consistent with Applicable Law.

D. Annual Reports.

At least annually, Utility shall cause a firm of independent certified public accountants (which may provide other services to Utility) to prepare, and Utility will deliver to DWR and its Assign(s), a report addressed to Utility (which may be included as part of Utility's customary auditing activities), for the information and use of DWR, to the effect that such firm has performed certain procedures (the scope of which shall be agreed upon with DWR) in connection with Utility's compliance with its obligations under this Servicing Order during the preceding year, identifying the results of such procedures and including any exceptions noted. Utility will deliver a copy of each report prepared hereunder to the Commission (at the address specified in section 14.14) at the same time it delivers each such report to DWR.

E. Annual Certifications.

At least annually, Utility will deliver to DWR, with a copy to the Commission, a certificate of an authorized officer certifying that to the best of such officer's knowledge, after a review of Utility's performance under this Servicing Order, Utility has fulfilled its obligations under this Servicing Order in all material respects and is in compliance herewith in all material respects.

F. Additional Applicable Laws.

DWR agrees, and SDG&E is ordered to make an effort to promptly notify the other Party in writing to the extent such Party becomes aware of any new Applicable Laws or changes (or proposed changes) in Applicable Tariffs hereafter enacted, adopted or promulgated that may have a material adverse effect on either Party's ability to perform its duties under this Servicing Order. DWR agrees, and with respect to SDG&E it is ordered that a Party's failure to so notify the other Party pursuant to this Section 8.6 will not constitute a material breach of this Servicing Order, and will not give rise to any right to terminate this Servicing Order or cause either Party to incur any liability to the other Party or any third party.

G. Other Information.

Upon the reasonable request of DWR or its Assign(s), Utility shall provide to the Commission and to DWR or its Assign(s) any public financial information in respect of the Utility applicable to Services provided by Utility under this Servicing Order, or any material information regarding the sale of DWR Power, surplus Power or the collection of DWR Charges, to the extent such information is reasonably available to Utility, which (i) is reasonably necessary and permitted by Applicable Law to monitor the performance by Utility hereunder, or (ii) otherwise relates to the exercise of DWR's rights or the discharge of DWR's duties under this Servicing Order or any Applicable Law. In particular, but without limiting the foregoing, Utility shall provide to DWR, with a copy to the Commission, any such information that is necessary or useful to calculate DWR's revenue requirements (as described in Sections 80110 and 80134 of the California Water Code) or DWR Charges or DWR Surplus Energy Sales Revenues.

H. Customer Confidentiality.

Nothing in this Section 8 shall affect the obligation of Utility to observe any Applicable Law prohibiting disclosure of information regarding Customers, and the failure of Utility to provide access to such information as a result of such obligation shall not constitute a breach of this Section 8 or this Servicing Order.

VI. Representations and Warranties.

a. Each person executing this Servicing Order for the respective Parties expressly represents and warrants that he or she has authority to bind the Party on whose behalf he or she has executed this Servicing Order.
b. Each Party represents and warrants that it has the full power and authority to execute and deliver this Servicing Order and to perform its terms, that execution, delivery and performance of this Servicing Order have been duly authorized by all necessary corporate or other action by such Party, and that this Servicing Order constitutes such Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

VII. Amendment Upon Changed Circumstances.

a. The Parties are informed that compliance with any Commission decision, legislative action or other governmental action (whether issued before or after the Effective Date of this Servicing Order) affecting the operation of this Servicing Order, including but not limited to (i) dissolution of the ISO, (ii) changes in the ISO market structure, (iii) a decision regarding the "Fixed Department of Water Resources Set-Aside" as such term is defined in Section 360.5 of the California Public Utilities Code, (iv) the establishment of other Governmental Programs, (v) the establishment or implementation of Bonds Charge or related changes ordered by the Commission, (vi) the imposition of an Exit Fee or similar DWR Charge upon Customers of Electric Service Providers or upon any other third party, (vii) the modification of the Operating Order or (viii) the modification of provisions related to the sales of surplus Power made on behalf of DWR to third parties by Utility, may require that amendment(s) be made t o this Servicing Order. If either Party reasonably determines that such a decision or action would materially affect the Services to be provided hereunder or the reasonable costs thereof, then upon the issuance of such decision or the approval of such action (unless and until it is stayed), DWR agrees, and SDG&E is ordered to negotiate the amendment(s) to this Servicing Order that is (or are) appropriate in order to effectuate the required changes in Services to be provided or the reimbursement thereof. Notwithstanding Section 5.4, if the Parties are unable to reach agreement on such amendments within 60 days after the issuance of such decision or approval of such action, DWR may, and SDG&E shall , submit the disagreement to the Commission for proposed resolution, in accordance with Applicable Law. Nothing herein shall preclude either Party from challenging the decision or action which such Party deems may adversely affect its interests in any appropriate forum of the Party's choosing.
b. The Parties are informed that this Servicing Order has not been reviewed by the rating agencies which are rating DWR's bonds. If the rating agencies request changes to this Servicing Order, DWR agrees, and SDG&E is ordered to negotiate to amend this Servicing Order to accommodate the rating agency requests and will cooperate in obtaining approvals of the Commission for such amendments.
c. The Parties are informed that this Servicing Order shall be modified to implement the California Governor's Executive Order D-39-01, dated June 9, 2001, concerning load curtailment programs. Therefore, the Parties agree to negotiate an amendment to this Servicing Order and to cooperate in obtaining approvals of the Commission for such amendment.

VIII. Data Retention.

DWR agrees, and with respect to SDG&E it is ordered that all data associated with the provision and receipt of services pursuant to this Servicing Order shall be maintained for the greater of (a) the retention time required by Applicable Law or Applicable Tariffs for maintaining such information, or (b) three years.

IX. Indemnity.

It is ordered that Utility and, to the extent allowed under Applicable Law, DWR agrees that it (each, the "Indemnifying Party") shall defend, indemnify, and hold the other Party, together with its affiliates, and each of their respective officers, agents, employees, assigns and successors in interest (collectively, the "Indemnified Party"), harmless from and against all claims, losses, demands, actions and expenses, damages and liabilities of any nature whatsoever (collectively "Claims") with respect to the acts or omissions of the Indemnifying Party or its officers, agents, contractors and employees or with respect to Indemnifying Party's performance of its obligations under this Servicing Order. DWR agrees, and with respect to SDG&E it is ordered that notwithstanding the above, the provisions of this Section 12 shall not apply to any Claims to the extent they involve the negligence, gross negligence, recklessness, willful misconduct or breach of this Servicing Order by either Indemnified Party. DW R agrees, and with respect to SDG&E it is ordered that each Indemnified Party shall bear its own attorneys' fees and costs under this Section 12. DWR agrees, and with respect to SDG&E it is ordered that the Indemnifying Party's obligations under this Section 12 shall survive termination of this Servicing Order. This Section 12 notwithstanding, DWR has made no representation that it has the express or implied legal authority to perform any obligation under this Section 12.

X. Limitations on Liability.

A. Consequential Damages.

DWR agrees, and with respect to SDG&E it is ordered that in no event will either Party be liable to the other Party for any indirect, special, exemplary, incidental, punitive, or consequential damages under any theory. Nothing in this Section 13.1 shall limit either Party's rights as provided in Section 12 above.

B. Limited Obligations of DWR and Utility.

DWR agrees that it will be liable for all amounts owing to Utility for the Services hereunder, irrespective of (a) any Customer's failure to make full and timely payments owed for DWR Charges, or (b) Utility's rights under Sections 4.3 and 7.2 to deduct certain amounts in calculating Remittances owing by Utility to DWR under Attachment B. Utility will not be required at any time to advance or pay any of its own funds in the fulfillment of its responsibilities hereunder with respect to DWR Charges, except to the extent provided otherwise in Attachments B, H and J hereto. DWR agrees that any amounts payable by DWR under this Servicing Order shall be payable solely from moneys on deposit in the Department of Water Resources Electric Power Fund established pursuant to Section 80200 of the California Water Code (the "Fund"). Neither the full faith and credit nor the taxing power of the State of California are or may be pledged for any payment under this Servicing Order. Revenues and assets of the Stat e Water Resources Development System are not available to make payments under this Servicing Order. If moneys on deposit in the Fund are insufficient to pay all amounts payable by DWR under this Servicing Order, or if DWR has reason to believe such funds may become insufficient to pay all amounts payable by DWR under this Servicing Order, DWR agrees to diligently pursue an increase to its revenue requirements as permitted under the Act from the appropriate Governmental Authority as soon as practicable.

XI. Miscellaneous.

A. Independent Contractor.

Utility and its agents and employees shall perform their obligations under this Servicing Order as independent contractors and not as officers or employees of the State of California. Notwithstanding the above, Utility shall act as the agent of DWR in billing and collecting DWR Charges and DWR Surplus Energy Sales Revenues hereunder, as provided in the Act and Section 80106 of the California Water Code.

B. Remedies Cumulative.

DWR agrees, and with respect to SDG&E it is ordered that except as otherwise provided in this Servicing Order, all rights of termination, cancellation, or other remedies in this Servicing Order are cumulative. DWR agrees, and with respect to SDG&E, it is ordered that use of any remedy shall not preclude any other remedy available under this Servicing Order.

C. Assignment.

a. DWR agrees, and with respect to SDG&E, it is ordered that except as provided in paragraphs (b), (c) and (d) below, neither Party shall assign or otherwise dispose of this Servicing Order, its right, title or interest herein or any part hereof to any entity, without the prior written consent of the other Party. DWR agrees, and with respect to SDG&E, it is ordered that no assignment of this Servicing Order shall relieve the assigning Party of any of its obligations under this Servicing Order until such obligations have been assumed by the assignee. DWR agrees, and with respect to SDG&E, it is ordered that when duly assigned in accordance with this Section 14.3(a) and when accepted by the assignee, this Servicing Order shall be binding upon and shall inure to the benefit of the assignee. DWR agrees, and with respect to SDG&E, it is ordered that any assignment in violation of this Section 14.3(a) shall be void.
b. Notwithstanding the provisions of this Section 14.3, Utility may delegate its duties under this Servicing Order to an agent or subcontractor, provided that Utility shall remain fully responsible for performance of any delegated duties and shall provide DWR with 30 calendar days' prior written notice of any such delegation, and further provided that such delegation does not, in the sole discretion of DWR, materially adversely affect DWR's or its Assigns' interests hereunder.
c. DWR agrees, and with respect to SDG&E it is ordered that DWR may assign or pledge its rights to receive performance (including payment of Remittances) hereunder to a trustee or another party ("Assign(s)") in order to secure DWR's obligations under its bonds (as that term is defined in the Act), and any such Assign shall be a third party beneficiary of this Servicing Order; provided, however, that this authority to assign or pledge rights to receive performance hereunder shall in no event extend to any person or entity that sells power or other goods or services to DWR. Notwithstanding the immediately preceding sentence, DWR may assign or pledge its rights to receive Remittances hereunder to another party in order to secure DWR's other obligations under the Act.
d. Any person (i) into which Utility may be merged or consolidated, (ii) which may result from any merger or consolidation to which Utility shall be a party or (iii) which may succeed to the properties and assets of Utility substantially as a whole, which person in any of the foregoing cases executes an agreement of assumption to perform every obligation of the Utility hereunder, shall be the successor to Utility under this Servicing Order without further act on the part of any of the Parties to this Servicing Order; provided, however, that Utility shall have delivered to DWR and its Assign(s) an opinion of counsel reasonably acceptable to DWR stating that such consolidation, merger or succession and such agreement of assumption complies with this Section 14.3(d) and that all of Utility's obligations hereunder have been validly assumed and are binding on any such successor or assign.
e. Notwithstanding anything to the contrary herein, DWR's rights and obligations hereunder shall be transferred, without any action or consent of either Party hereto, to any entity created by the State legislature which is required under Applicable Law to assume the rights and obligations of DWR under Division 27 of the California Water Code.

D. Force Majeure.

Neither Party shall be liable for any delay or failure in performance of any part of this Servicing Order (including the obligation to remit money at the times specified herein) from any cause beyond its reasonable control, including but not limited to, unusually severe weather, flood, fire, lightning, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or Government Authority, or any combination of these causes, which by the exercise of due diligence and foresight such Party could not reasonably have been expected to avoid and which by the exercise of due diligence is unable to overcome. An Insolvency Event shall not constitute *force majeure*. Notwithstanding anything to the contrary above, DWR agrees, and with respect to SDG&E it is ordered that each Party's obligation to pay money hereunder shall continue to the extent such Party is able to make such payment, and any amounts owed by Utili ty hereunder and received by Utility shall be held in trust for DWR (whether or not held together with other monies) and remitted to DWR as soon as reasonably practicable. DWR agrees, and with respect to SDG&E it is ordered that any amounts paid or remitted pursuant to this Section 14.4 shall not bear interest which would otherwise accrue under Section 7.

E. Severability.

DWR agrees, and with respect to SDG&E it is ordered in the event that any one or more of the provisions of this Servicing Order shall for any reason be held to be unenforceable in any respect under Applicable Law, such unenforceability shall not affect any other provision of this Servicing Order, but this Servicing Order shall be construed as if such unenforceable provision or provisions had never been contained herein.

F. Third-Party Beneficiaries.

The provisions of this Servicing Order are exclusively for the benefit of the Parties and any permitted assignee of either Party.

G. Governing Law.

This Servicing Order shall be interpreted, governed and construed under the laws of the State of California as if executed and performed wholly within the State of California.

H. Reserved.

I. Section Headings.

Section and paragraph headings appearing in this Servicing Order are inserted for convenience only and shall not be construed as interpretations of text.

J. Entire Servicing Order; Applicable Law.

a. This Servicing Order, including all attachments and agreements contemplated herein, contains all of the terms and conditions between the Parties as to the subject matter of this Servicing Order, and merges and supersedes all prior oral or written agreements, commitments, representations and discussions between the Parties or made to third parties regarding the subject matter of this Servicing Order, except that this Servicing Order and the Parties' obligations hereunder shall be subject in all cases to the provisions of Applicable Law, and except that this Servicing Order shall have no effect on the terms of any agreement between DWR and Utility, as modified from time to time after the Execution Date hereof, referenced in Attachment E hereto. Furthermore, no default under any such other agreement between the Parties shall constitute a default hereunder, and each party hereby waives any right to set off any amounts owing to it under any such other agreement against any amounts owing hereunder.
b. Should a conflict exist between the provisions contained in this Servicing Order (including the attachments hereto) and either Applicable Law or the 20/20 Program, the provisions of Applicable Law or the 20/20 Program, as the case may be, shall govern. The General Terms and Conditions contained in Attachment D are hereby incorporated by reference. In the event of a conflict between the provisions of this Servicing Order and any attachment hereto (including Service Attachment 1), then the provisions of the attachment shall govern. Nothing in this subsection (b) shall relieve the Parties from complying with their obligations under Section 10 to make amendments to this Servicing Order to reflect changed circumstances, including any amendments necessary due to amendments or supplements to the Operating Order or due to necessary reconciliation with the Operating Order.

K. Amendments.

No amendment, modification, or supplement to this Servicing Order shall be effective unless it is in writing and signed by the authorized representatives of both Parties and approved as required, and by reference incorporates this Servicing Order and identifies the specific portions that are amended, modified, or supplemented or indicates that the material is new. No oral understanding or agreement not incorporated in this Servicing Order is binding on either of the Parties.

L. Waivers.

DWR agrees, and with respect to SDG&E, it is ordered that none of the provisions of this Servicing Order shall be considered waived by either Party unless the Party against whom such waiver is claimed gives such waiver in writing. DWR agrees, and with respect to SDG&E, it is ordered that the failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Servicing Order or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect. DWR agrees, and with respect to SDG&E, it is ordered that waiver by either Party of any default by the other Party shall not be deemed a waiver of any other default.

M. Reserved.

N. Notices and Demands.

a. DWR agrees, and with respect to SDG&E, it is ordered that except as otherwise provided under this Servicing Order, all notices, demands, or requests pertaining to this Servicing Order shall be in writing and shall be deemed to have been given (i) on the date delivered in person, (ii) on the date when sent by facsimile (with receipt confirmed by telephone by the intended recipient or his or her authorized representative) or electronic transmission (with receipt confirmed telephonically or electronically by the intended recipient or his or her authorized representative) or by special messenger, or (iii) 72 hours following delivery to a United States post office when sent by certified or registered United States mail postage prepaid, and addressed as set forth below:

   Utility: San Diego Gas & Electric Company
   Customer Service Solutions
   8335 Century Park Court, CP11E
   San Diego, California 92123

   Attn: Dawn Osborne
   Direct Access Strategy & Policy Manager
   Telephone: (858) 654-1275
   Facsimile: (858) 654-1256
   Email: dosborne@sdge.com

   DWR: State of California
   The Resources Agency
   Department of Water Resources
   California Energy Resources Scheduling Division
   3310 El Camino Avenue, Suite 120
   Sacramento, California 95821

   Attn: Peter S. Garris
   Deputy Director
   Telephone: (916) 574-2733
   Facsimile: (916) 574-0301
   Email: pgarris@water.ca.gov

b. DWR agrees, and with respect to SDG&E, it is ordered that each Party shall be entitled to specify as its proper address any other address in the United States, or specify any change to the above information, upon written notice to the other Party complying with this Section 14.14.
c. DWR agrees, and with respect to SDG&E, it is ordered that each Party shall designate on Attachment A the person(s) to be contacted with respect to specific operational matters. Each Party shall be entitled to specify any change to such person(s) upon written notice to the other Party complying with this Section 14.14.
d. DWR agrees, and with respect to SDG&E, it is ordered that copies of documents required by this Servicing Order to be delivered to the Commission shall be delivered in accordance with this Section 14.14 and shall be addressed as set forth below:

California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Attn: Paul Clanon
Energy Division Director
Telephone: (415) 703-2237
Facsimile: (415) 703-2200
Email: pac@cpuc.ca.gov

O. Good Faith.

DWR agrees to, and SDG&E is ordered to perform all its actions, obligations and duties in connection with this Servicing Order in good faith.

P. Approval.

This Servicing Order shall be effective when approved by the Commission. Except as expressly provided otherwise herein, neither Party may commence performance hereunder until such date. Any delay in the commencement of performance hereunder as a consequence of waiting for such approval(s) shall not be a breach or default under this Servicing Order.

DWR has determined, pursuant to Section 80014(b) of the California Water Code, that application of certain provisions of the Government Code and Public Contract Code applicable to State contracts, including but not limited to advertising and competitive bidding requirements and prompt payment requirements, would be detrimental to accomplishing the purposes of Division 27 (commencing with Section 80000) of the California Water Code and that such provisions and requirements are therefore not applicable to or incorporated in this Servicing Order.

The First Amended and Restated Servicing Agreement as amended by Amendment No. 1 (the "original Servicing Agreement"), as further amended by the changes set forth in this 2003 Servicing Order, shall remain in full force and effect. All references to the "Servicing Agreement" or to the "Agreement" in the original Servicing Agreement or in this 2003 Servicing Order shall hereafter mean the 2003 Servicing Order, unless the context requires a different interpretation. The Parties intend this 2003 Servicing Order to amend the original Servicing Agreement, and in the event of irreconcilable conflict between the terms of the original Servicing Agreement and this 2003 Servicing Order, the terms of this 2003 Servicing Order shall control. The 2003 Servicing Order shall be effective at such time it has been executed by both Parties and approved by the Commission, and until such time, the original Servicing Agreement shall remain in full force and effect.

Q. Attachments.

The following attachments are incorporated in this Servicing Order:

Service Attachment 1 -- Consolidated Utility Billing Services
Service Attachment 2 -- Wholesale Trading, Invoicing and Collection Services
Attachment A -- Representatives and Contacts
Attachment B -- Remittance Methodology
Attachment C -- Sample Daily and Monthly Reports
Attachment D -- General Terms and Conditions
Attachment E -- Additional Provisions
Attachment F -- Calculation Methodology for Reduced Remittances Pursuant to 20/20 Program
Attachment G -- Fee Schedule
Attachment H -- Adjustments to DWR Charges for Variances in DWR Power Delivered
Attachment I -- Reserved

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SERVICE ATTACHMENT 1

SAN DIEGO GAS & ELECTRIC COMPANY

CONSOLIDATED UTILITY BILLING SERVICES

SERVICE ATTACHMENT 1

SAN DIEGO GAS & ELECTRIC COMPANY

CONSOLIDATED UTILITY BILLING SERVICES

Section 1. Establishment and Maintenance of Consolidated Utility Billing.

Under Consolidated Utility Billing, Utility will include the DWR Charges with its Utility Charges on the Customer's Bill.

Section 2. Customer Billing Procedures.

2.1. Compliance with Metering Standards. Except to the extent such services are provided by a third party:

(a) Utility shall comply with all metering standards pursuant to Applicable Tariffs.

(b) Utility shall read and validate data from meters, and edit and estimate such data, under the terms of Applicable Tariffs.

(c) Utility shall maintain, store and provide current and historical meter and usage data as required by Applicable Tariffs.

2.2. Presentation of DWR Charges on Consolidated Utility Bill.

(a) DWR Charges shall appear on all Consolidated Utility Bills in the manner and at the time required by Applicable Law and Applicable Tariffs.

(b) Notwithstanding subsection (a) above, the Utility may change the manner of bill presentation of DWR Charges upon the agreement of DWR or at the request of DWR and upon agreement by the Utility. Such agreement by DWR or Utility is not to be unreasonably withheld.

(c) Notwithstanding subsections (a) and (b) above, no change shall be made to Consolidated Utility Bill formats without the approval of the Commission, if the Commission's approval is required under Applicable Law and Applicable Tariffs.

a. Notwithstanding subsections (a), (b) and (c), above, the Consolidated Utility Bill shall, upon Commission implementation of Bond Charges, (i) at all times thereafter contain a separate line item for Bond Charges and (ii) so long as DWR is providing Power to Customers, contain a statement to the effect that the Consolidated Utility Bill includes Charges for power provided by DWR for which DWR is collecting "X" cents per kilowatt hour (where X= the current Power Charge). DWR shall pay Utility its incremental costs incurred to implement the separate line for Bond Charges as additional fees for additional services in accordance with Section 7 and Attachment G of this Servicing Order.

2.3. Billing Costs.

DWR agrees that Utility shall be reimbursed for the reasonable costs of the Billing Services it performs for DWR under this Servicing Order, except for those costs that would have been incurred in providing Billing Services for Customers in the absence of this Servicing Order. DWR agree that the Commission has jurisdiction to address any dispute concerning the reasonableness of the costs of Billing Services charged to DWR under this Servicing Order.

2.4. Adjustments to DWR Charges.

Utility will resolve all disputes with Customers relating to DWR Charges consistent with Applicable Tariffs and prevailing industry standards. Utility will not waive any late payment fee or modify the terms of payment of any amounts payable by Customer unless such action is consistent with the action taken with respect to its own Charges and Applicable Tariffs. In the event that DWR is entitled by Applicable Law to collect Exit Fees as a component of DWR Charges, DWR agrees, and SDG&E is ordered to negotiate the amendment(s) to this Servicing Order that is (or are) appropriate in order to facilitate the calculation and collection of such Exit Fees, and any such amendment shall be submitted to the Commission for approval.

2.5. Format of Consolidated Utility Bills.

Utility shall conform to such requirements in respect of the format, structure and text of Consolidated Utility Bills as Applicable Law and Applicable Tariffs shall from time to time prescribe. Utility shall, subject to the requirements of Sections 1 and 2 of this Service Attachment 1, determine the format and text of Consolidated Utility Bills in accordance with its reasonable business judgment, and its policies and practices with respect to its own charges.

2.6. Customer Notices.

a. If DWR Charges are revised at any time, Utility shall, to the extent and in the manner and timeframe required by Applicable Law, provide Customers with notice announcing such revised DWR Charges. Such notice shall, as appropriate, include publication, inserts to or in the text of the bills or on the reverse side of bills delivered to Customers, and/or such other means as Utility may from time to time use to communicate with its customers. The format of any such notice shall be determined by the mutual agreement of the Parties, subject to approval by the Commission's public advisor.
b. In addition, at least once each year, to the extent permitted by Applicable Law, Utility shall cause to be prepared and delivered to Customers a notice stating, in effect, that DWR Power and DWR Charges are owned by DWR and not Utility. Such notice shall be included, in a manner and format to be agreed upon by the Parties, subject to approval by the Commission's public advisor, either as an insert to or in the text of the bills or on the reverse side of bills delivered to such Customers or shall be delivered to Customers by electronic means or such other means as Utility may from time to time use to communicate with its Customers.

2.7. Delivery.

Utility shall deliver all Consolidated Utility Bills (i) by United States Mail in such class or classes as are consistent with polices and practices followed by Utility with respect to its own charges or (ii) by any other means, whether electronic or otherwise, that Utility may from time to time use to present its own charges to its customers. In the case of Consolidated Utility Billing Service, Utility shall pay from its own funds all costs of issuance and delivery of Consolidated Utility Bills, including but not limited to printing and postage costs as the same may increase or decrease from time to time, except to the extent that the presentation of DWR Charges and any associated bill messages or notices (including, without limitation, bill inserts and published notices) materially increase the costs in which case such increase in costs shall be borne solely by DWR. To the extent practicable, Utility agrees to give DWR seven calendar days prior written notice of any such additional costs. A ny such increased costs shall be invoiced to DWR as Additional Charges and shall be subject to the provisions of Section 7 of the Servicing Order.

Section 3. Customer Payments.

Utility shall permit Customers to pay DWR Charges through any of the payment options then offered by Utility to Customers for payment of Utility Charges appearing on the Consolidated Utility Bill. Utility shall not permit Customers to direct how partial payments of balances due on Consolidated Utility Bills will be applied. Utility will credit all payments received from a Customer as set forth in Attachment B hereto.

Section 4. Collection and Nonpayment.

4.1. Collection of DWR Charges.

Utility will collect DWR Charges in accordance with its standard practices, and will notify Customers of amounts overdue for DWR Charges in accordance with such practices. Such collection practices shall conform to all requirements of Applicable Law and Applicable Tariffs. Utility will post all payments for DWR Charges as promptly as practicable, but in no case less promptly than Utility posts payments for Utility Charges.

4.2. Termination of Customer's Electrical Service.

Utility shall adhere to and carry out disconnection policies in accordance with Applicable Law.

Section 5. Taxes and Fees Service.

Subject to Section 7.3, Utility will collect and remit to the various authorities the taxes and fees assessed to Customers on the DWR Charges.

Section 6. Late Payments.

In the event that Utility receives late payment interest charges from a Customer, such payment shall be allocated to DWR based upon the same proportion that DWR Charges bear to the total Utility Charges on the Consolidated Utility Bill. Utility shall not allocate to DWR any other late payment service charges or collection fees (including but not limited to disconnection or reconnection services or similar charges related to Customer defaults).

SERVICE ATTACHMENT 2

SAN DIEGO GAS & ELECTRIC COMPANY

WHOLESALE TRADING, BILLING, COLLECTION OF SURPLUS POWER SALES

EXHIBIT 10.10

SEMPRA ENERGY

2003 EXECUTIVE INCENTIVE

PLAN B

TABLE OF CONTENTS

I. PURPOSE

The purpose of the 2003 Sempra Energy Executive Incentive Plan B (the "Plan") is to attract and retain highly qualified individuals; to obtain from each the best possible performance; to establish performance goals based on objective criteria; and to include in such individual's compensation package an incentive component that is tied directly to the achievement of those objectives.

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II. EFFECTIVE DATE; TERM

The Plan is effective as of January 1, 2003, subject to approval by the Compensation Committee (the "Compensation Committee") of the Board of Directors (the "Board of Directors"), and shall remain in effect until such time as it shall be terminated by the Compensation Committee of Sempra Energy or any successor thereto.

III. ELIGIBILITY AND PARTICIPATION

Eligibility to participate in the Plan is limited to officers or employees of the Company as designated by the Compensation Committee, who through their position and performance, have the opportunity to contribute substantially to the attainment of the financial objectives of the Company. Officers or employees who the Compensation Committee determines are or may be "covered employees" within the meaning of Section 162(m) of the Code are not eligible to participate in the Plan. Participants in the Plan ("Participants") shall be selected from time to time with respect to each performance period by the Compensation Committee from those eligible to participate in the Plan, which Participants shall be designated in writing.

IV. PERFORMANCE GOAL

The Plan's performance goals shall be determined by the Compensation Committee, and may include financial, operational, and individual performance measures. Within ninety days after the commencement of the award period, the Committee shall set forth the performance measures, the relative weighting of each measure, and the threshold, target, and maximum performance levels for each measure.

Subject to the foregoing and to the limitations set forth in Section V, no awards shall be paid to Participants unless and until the Compensation Committee makes a certification in writing with respect to the attainment of the performance goals.

V. DETERMINATION OF AWARDS

The Compensation Committee shall have authority to exercise discretion in determining the amount of the targeted award granted to each Participant at the beginning of a performance period. The Compensation Committee shall determine the targeted awards for any performance period no later than 90 days after the commencement of the performance period and while the performance relating to the performance goal remains substantially uncertain.

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The Compensation Committee shall have authority to exercise discretion to increase or reduce the amount of any targeted award which shall be payable to any Participant at the end of each performance period, subject to the terms, conditions and limits of the Plan and of any other written commitment authorized by the Compensation Committee. The Compensation Committee may at any time establish (and once established, rescind, waive or amend) additional conditions and terms of payment of awards (including but not limited to the achievement of other financial, strategic or individual goals, which may be objective or subjective) as it deems desirable in carrying out the purposes of the Plan and may take into account such other factors as it deems appropriate in administering any aspect of the Plan. In determining the amount of any award to be granted or to be paid to any Participant, the Compensation Committee shall give consideration to the contribution which may be or has been made by the Participant to achievement of the Company's established objectives and such other matters as it shall deem relevant.

The payment of an award to a Participant with respect to a performance period shall be conditioned upon the Participant's employment by the Company on the last day of the performance period; provided, however, that in the discretion of the Compensation Committee, awards may be paid to Participants who have retired, died or have become disabled or whose employment with the Company has been terminated without cause prior to the last day of the performance period, subject to all other terms and conditions of the Plan.

VI. FORM OF AWARDS

All awards shall be determined by the Compensation Committee and shall be paid in cash or in Common Stock of the Company or in a combination of cash and Common Stock, as determined by the Committee in its discretion. Before the beginning of each performance period, each Participant may elect that all or part of the Participant's award for that period will be deferred and distributed at a later date under The Sempra Energy Deferred Compensation and Excess Savings Plan subject to the terms of the such plan or under any other plan designated by the Committee that provides for the deferral of compensation by Participants. Any shares of Common Stock paid to Participants under the Plan shall be paid pursuant to the Company's 1998 Long Term Incentive Plan or any other plan designated by the Compensation Committee that provides for the award of Common Stock to Participants.

VII. PAYMENT OF AWARDS

Awards may be paid at any time following the end of the performance period; provided, however, that no awards shall be paid unless and until the Compensation Committee certifies, in writing, the satisfaction of the financial and operational performance goals for the performance period.

VIII. SPECIAL AWARDS AND OTHER PLANS

Nothing contained in the Plan shall prohibit the Company from granting awards or authorizing other compensation to any person under any other plan or authority or limit the authority of the Company to establish other special awards or incentive compensation plans providing for the payment of incentive compensation to employees (including those employees who are eligible to participate in the Plan).

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IX. ADMINISTRATION, AMENDMENT AND INTERPRETATION OF THE PLAN

The Compensation Committee shall administer the Plan. The Compensation Committee shall consist solely of two or more members of the board of directors who shall qualify as "outside directors" under Section 162(m) of the Code. The Compensation Committee shall have full power to construe and interpret the Plan, establish and amend rules and regulations for its administration, and perform all other acts relating to the Plan, including the delegation of administrative responsibilities, that it believes reasonable and proper and in conformity with the purposes of the Plan.

The Compensation Committee shall have the right to amend the Plan from time to time or to repeal it entirely or to direct the discontinuance of awards either temporarily or permanently.

Any decision made, or action taken, by the Compensation Committee arising out of or in connection with the interpretation and/or administration of the Plan shall be final, conclusive and binding on all persons affected thereby.

X. RIGHTS OF PLAN PARTICIPANTS

Neither the Plan, nor the adoption or operation of the Plan, nor any documents describing or referring to the Plan (or any part hereof) shall confer upon any Participant any right to continue in the employ of the Company or shall interfere with or restrict in any way the rights of the Company, which are hereby expressly reserved, to discharge any Participant at any time for any reason whatsoever, with or without cause.

No individual to whom an award has been made or any other party shall have any interest in the cash or any other asset of the Company prior to such amount being paid.

No right or interest of any Participant shall be assignable or transferable, or subject to any claims of any creditor or subject to any lien.

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XI. MISCELLANEOUS

The Company shall deduct all federal, state and local taxes required by law or Company policy from any award paid hereunder.

In no event shall the Company be obligated to pay to any Participant an award for any period by reason of the Company's payment of an award to such Participant in any other period, or by reason of the Company's payment of an award to any other Participant or Participants in such period or in any other period. Nothing contained in this Plan shall confer upon any person any claim or right to any payments hereunder. Such payments shall be made at the sole discretion of the Compensation Committee.

The Plan shall be unfunded. Amounts payable under the Plan are not and will not be transferred into a trust or otherwise set aside. The Company shall not be required to establish any special or separate fund or to make any other segregation of assets to assure the payment of any award under the Plan. Any accounts under the Plan are for bookkeeping purposes only and do not represent a claim against the specific assets of the Company.

Any provision of the Plan that is prohibited or unenforceable shall be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions of the Plan.

The Plan and the rights and obligations of the parties to the Plan shall be governed by, and construed and interpreted in accordance with, the law of the State of California (without regard to principles of conflicts of law).

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AMENDMENT NO. 7

SAN DIEGO GAS & ELECTRIC COMPANY

NUCLEAR FACILITIES QUALIFIED

CPUC DECOMMISSIONING MASTER TRUST

AGREEMENT

FOR SAN ONOFRE NUCLEAR GENERATING STATIONS

WHEREAS, the California Public Utilities Commission, San Diego Gas & Electric Company, and Mellon Bank, N.A. (the "Parties") have executed the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Stations, as amended, (the "Master Trust Agreement") and the Parties desire to amend the Master Trust Agreement;

NOW, THEREFORE, the Master Trust Agreement is amended as provided herein below effective December 24, 2003.

The introductory text of Article II is amended to read as follows:

II.

DISPOSITIVE PROVISIONS

After payment of the expenses described in Section 6.01 hereof, the Trustee shall distribute the Master Trust as provided in this Article II. Except for payments or disbursements made pursuant to Section 2.01 or as otherwise permitted under paragraph 50.82(a)(8) of Title 10 of the Code of Federal Regulations, no disbursement or payment may be made from the Master Trust until written notice of the intention to make disbursement or payment has been given to the Nuclear Regulatory Commission Director of the Office of Nuclear Regulation, or Director of the Office of Nuclear Material Safety and Safeguards, as applicable, at least 30 working days before the date of the intended disbursement or payment.

IN WITNESS WHEREOF, the Parties have executed this Amendment No. 7 effective December 24, 2003.

CALIFORNIA PUBLIC UTILITIES COMMISSION

By:____

Title:______________________________________

SAN DIEGO GAS & ELECTRIC COMPANY

By:____ Attest:______________________________

Title:_______________________________________ Title: _______________________________

MELLON BANK, N. A.

By:____ Attest: _____________________________

Title:_______________________________________ Title: ______________________________

AMENDMENT NO. 5

SAN DIEGO GAS & ELECTRIC COMPANY

NUCLEAR FACILITIES NONQUALIFIED

CPUC DECOMMISSIONING MASTER TRUST

AGREEMENT

FOR SAN ONOFRE NUCLEAR GENERATING STATIONS

WHEREAS, the California Public Utilities Commission, San Diego Gas & Electric Company, and Mellon Bank, N.A. (the "Parties") have executed the San Diego Gas & Electric Company Nuclear Facilities Nonqualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Stations, as amended, (the "Master Trust Agreement") and the Parties desire to amend the Master Trust Agreement;

NOW, THEREFORE, the Master Trust Agreement is amended as provided herein below effective December 24, 2003.

The introductory text of Article II is amended to read as follows:

II

DISPOSITIVE PROVISIONS

After payment of the expenses described in Section 6.01 hereof, the Trustee shall distribute the Master Trust as provided in this Article II. Except for payments or disbursements made pursuant to Section 2.01 or as otherwise permitted under paragraph 50.82(a)(8) of Title 10 of the Code of Federal Regulations, no disbursement or payment may be made from the Master Trust until written notice of the intention to make disbursement or payment has been given to the Nuclear Regulatory Commission Director of the Office of Nuclear Regulation, or Director of the Office of Nuclear Material Safety and Safeguards, as applicable, at least 30 working days before the date of the intended disbursement or payment.

IN WITNESS WHEREOF, the Parties have executed this Amendment No. 5 effective December 24, 2003.

CALIFORNIA PUBLIC UTILITIES COMMISSION

By:____

Title:_______________________________________

SAN DIEGO GAS & ELECTRIC COMPANY

By:____ Attest: ___________________

Title:_______________________________________ Title: ____________________

MELLON BANK, N. A.

By:____ Attest: __________________

Title:_______________________________________ Title: ___________________

EXHIBIT 12.1
SEMPRA ENERGY
COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS
(Dollars in millions)

	1999	2000	2001	2002	2003
Fixed Charges and Preferred Stock Dividends:					
Interest	$ 233	$ 308	$ 358	$ 350	$ 351
Interest portion of annual rentals	10	8	6	6	5
Preferred dividends of subsidiaries (1)	16	18	16	15	11
Combined fixed charges and preferred stock dividends for purpose of ratio	$ 259	$ 334	$ 380	$ 371	$ 367
Earnings:					
Pretax income from continuing operations	$ 573	$ 699	$ 731	$ 721	$ 742
Total fixed charges (from above)	259	334	380	371	367
Less:					
Interest capitalized	1	3	11	29	26
Equity in income (loss) of unconsolidated subsidiaries and joint ventures	--	62	12	(55)	8
Total earnings for purpose of ratio	$ 831	$ 968	$ 1,088	$ 1,118	$ 1,075
Ratio of earnings to combined fixed charges and preferred stock dividends	3.21	2.90	2.86	3.01	2.93

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

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

INTRODUCTION

This section includes management's discussion and analysis of operating results from 2001 through 2003, and provides information about the capital resources, liquidity and financial performance of Sempra Energy and its subsidiaries (collectively referred to as "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 Financial Report.

OVERVIEW

Sempra Energy

Sempra Energy is a Fortune 500 energy services holding company. Its business units provide a wide spectrum of value-added electric and natural gas products and services to a diverse range of customers. Operations are divided between delivery services, which are comprised of the California utility subsidiaries, Sempra Energy Global Enterprises (Global) and Sempra Energy Financial as described below.

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                       |      Sempra Energy       |
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                       ----------------------------
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              ----------------------------------------------
              |                     |                    |
- -------------------------  ----------------------   -----------------
|                        |  |                    |   |               |
| California Utilities   |  |   Sempra Energy    |   | Sempra Energy |
|                        |  | Global Enterprises |   |   Financial   |
- ------------------------  |                    |   |               |
  |                         ----------------------   -----------------
  |  -------------------          |
  |--|                 |          |   --------------------
  |  |     Southern    |          |-- |                  |
  |  |    California   |          |   |  Sempra Energy   |
  |  |       Gas       |          |   |     Trading      |
  |  |                 |          |   |                  |
  |  -------------------          |   --------------------
  |                               |   --------------------
  |  --------------------         |---|                  |
  |--|                  |         |   |   Sempra Energy  |
     |   San Diego Gas  |         |   |    Resources     |
     |    & Electric    |         |   |                  |
     |                  |         |   --------------------
     --------------------         |   --------------------
                                  |---|                  |
                                  |   |   Sempra Energy  |
                                  |   |        LNG       |
                                  |   |                  |
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                                  |---|                  |
                                  |   |    Sempra Energy |
                                  |   |    International |
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                                  |---|                  |
                                      |   Sempra Energy  |
                                      |    Solutions     |
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Summary descriptions of the operating business units are provided below and further detail is provided throughout this section of the Financial Report.

The major events during 2003 affecting the results for the year and future years include the following:

- -- Favorable resolution of significant income-tax issues which increased 2003 earnings by $118 million;

- -- Favorable decisions, subject to appeal, upholding Sempra Energy Resources' (SER) contract with the California Department of Water Resources (DWR);

- -- California Public Utilities Commission (CPUC) settlement subject to appeal, relating to SDG&E's intermediate-term power-purchase contracts and recognition of the related $65 million after-tax gain;

- -- Rate-setting process for 2004 and future years nearing resolution for SoCalGas and SDG&E;

- -- Completion of construction for generating plants by the company's generation subsidiary;

- -- Entry into the liquefied natural gas (LNG) business in Baja California, Mexico and in Louisiana;

- -- The end of incentive-pricing ratemaking for the San Onofre Nuclear Generation Station (SONGS), 20% owned by SDG&E;

- -- Continuing preliminary proceedings related to a claim by the company's international business unit for compensation from the Argentine government for changes in natural gas tariffs;

- -- Continuing legal proceedings concerning anti-trust claims made against the company, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas);

- -- Write down of the carrying values of Frontier Energy and Atlantic Electric & Gas Limited (AEG); and

- -- Application of a new accounting principle, requiring consolidation of two affiliates.

The California Utilities

As of December 31, 2003, SoCalGas and SDG&E (the California Utilities) served over 22 million consumers. Natural gas service was provided throughout Southern California and portions of central California through over 6.2 million meters. Electric service was provided throughout San Diego County and portions of Orange County, both in Southern California, through 1.3 million meters.

Sempra Energy Global Enterprises (Global)

Global is a holding company for most of the subsidiaries of Sempra Energy that are not subject to California utility regulation.

Global's principal subsidiaries provide the following energy-related products and services:

- -- Sempra Energy Trading (SET) is a wholesale trader of physical and financial energy products, including natural gas, power, crude oil and other commodities, and a trader and wholesaler of metals, serving a broad range of customers;

- -- SER acquires, develops and operates power plants for the competitive market;

- -- Sempra Energy LNG Corp. (SELNG) is developing regasification terminals for LNG;

- -- Sempra Energy International (SEI) engages in energy-infrastructure projects outside the United States and, as of December 31, 2003, had interests in companies that provide natural gas or electricity services to over 2.8 million customers in Argentina, Chile, Mexico and Peru and in two small natural gas distribution utilities in the eastern United States; and

- -- Sempra Energy Solutions (SES) provides energy-related products and services on a retail basis, including commodity sales to electricity and natural gas consumers and energy efficiency engineering services.

Sempra Energy Financial (SEF)

In order to reduce Sempra Energy's income taxes, SEF invests in limited partnerships which own 1,300 affordable-housing properties throughout the United States and holds an interest in a limited partnership that produces synthetic fuel from coal.

RESULTS OF OPERATIONS

Overall Operations

Net income was $649 million in 2003, a 9.8% increase over 2002, and earnings per diluted share was $3.03, an increase of 5.6%. The percentage increase in earnings per diluted share was less than the percentage increase in earnings due to the issuance of shares needed to finance the company's expanded Global business.

The following chart shows net income and diluted earnings per share for each of the five years following the formation of the company in 1998.

(Dollars in millions, except per share amounts)

	Net Income	Earnings Per Share
2003	$ 649	$ 3.03
2002	$ 591	$ 2.87
2001	$ 518	$ 2.52
2000	$ 429	$ 2.06
1999	$ 394	$ 1.66

Although operating income was less in 2003 than in 2002, there were many unusual items that affect this comparison. The following table summarizes the major factors affecting the comparison of net income and operating income for 2002 and 2003.

(Dollars in millions)	Net Income	Operating Income
2002	$ 591	$ 987
Extraordinary item in 2002	(16)	--
Merger savings in 2002	(25)	(42)
Income-tax settlements in 2002	(25)	--
California energy crisis litigation costs in 2002	13	23
	538	968
Income-tax settlements in 2003	118	--
SDG&E power contract settlement in 2003	65	116
Impairment of Frontier Energy assets in 2003	(47)	(77)
Impairment of AEG assets in 2003	(21)	(24)
California energy crisis litigation costs and SoCalGas sublease loss in 2003	(49)	(85)
SoCalGas' natural gas procurement awards in 2003	29	49
Changes in accounting principles in 2003:		
Repeal of EITF 98-10	(29)	--
Adoption of FIN 46	(17)	--
2003 impact of the repeal of EITF 98-10	9	15
Operations (2003 compared to 2002)	53	(23)
2003	$ 649	$ 939

California Utility Operations

To understand the operations and financial results of the California Utilities, it is important to understand the ratemaking procedures to which they are subject.

The California Utilities are subject to various regulatory bodies and rules at the national, state and local levels. The primary California body is the CPUC which regulates utility rates and operations. The primary national bodies are the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC). The FERC regulates interstate transportation of natural gas and electricity and various related matters. The NRC regulates nuclear generating plants. Local regulators and municipalities govern the placement of utility assets, including natural gas pipelines and electric lines. Other business units are also subject to regulation including, as the case may be, the FERC, various state commissions, local bodies, and various similar bodies in countries other than the United States.

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

Beginning on January 1, 2003, SDG&E and the other IOUs resumed their electric commodity procurement function. In addition, the CPUC established the allocation of the power purchased by the DWR under long-term contracts for the IOUs' customers and the related cost responsibility among the IOUs for that power. This is discussed further in Note 13 of the notes to Consolidated Financial Statements.

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. Restructuring is again being considered, as discussed in Note 14 of the notes to Consolidated Financial Statements.

See additional discussion of these matters under "Factors Influencing Future Performance" and in Notes 13 and 14 of the notes to Consolidated Financial Statements.

Natural Gas Revenue and Cost of Natural Gas. Natural gas revenues increased to $4.0 billion in 2003 from $3.3 billion in 2002, and the cost of natural gas increased to $2.1 billion in 2003 from $1.4 billion in 2002. Additionally, natural gas revenues increased to $1.0 billion for the three months ended December 31, 2003 from $971 million for the same period in 2002, and the corresponding cost of natural gas increased to $542 million in 2003 from $436 million in 2002. These changes were primarily attributable to natural gas price increases. For the year, this was partially offset by reduced volumes. Revenues also increased due to approved performance awards recognized during 2003. See discussion of performance awards in Note 14 of the notes to Consolidated Financial Statements.

Under the current regulatory framework, the cost of natural gas purchased for customers and the variations in that cost are passed through to the customers on a substantially concurrent basis. However, SoCalGas' Gas Cost Incentive Mechanism (GCIM) allows SoCalGas to share in the savings or costs from buying natural gas for customers below or above monthly benchmarks. The mechanism permits full recovery of all costs within a tolerance band above the benchmark price and refunds all savings within a tolerance band below the benchmark price. The costs or savings outside the tolerance band are shared between customers and shareholders. In addition, SDG&E's natural gas procurement Performance-Based Regulation (PBR) mechanism provides an incentive mechanism by measuring SDG&E's procurement of natural gas against a benchmark price comprised of monthly natural gas indices, resulting in shareholder rewards for costs achieved below the benchmark and shareholder penalties when costs exceed the benchmark. See further discussion in Notes 1 and 14 of the notes to Consolidated Financial Statements.

Natural gas revenues decreased to $3.3 billion in 2002 from $4.4 billion in 2001, and the cost of natural gas distributed decreased to $1.4 billion in 2002 from $2.5 billion in 2001. The decrease in natural gas revenues was primarily due to lower natural gas prices and decreased transportation charges related to electric generation plants and the North Baja pipeline's beginning of service in September 2002 (see Note 15 of the notes to Consolidated Financial Statements). The decrease in the cost of natural gas was primarily due to lower average natural gas commodity prices. For the fourth quarter, natural gas revenues increased to $971 million in 2002 from $773 million in 2001, and the cost of natural gas distributed increased to $436 million in 2002 from $319 million in 2001 due primarily to increased natural gas prices.

Electric Revenue and Cost of Electric Fuel and Purchased Power.
Electric revenues increased to $1.8 billion in 2003 from $1.3 billion in 2002, and the cost of electric fuel and purchased power increased to $0.5 billion in 2003 from $0.3 billion in 2002. Additionally, for the fourth quarter electric revenues increased to $419 million in 2003 from $320 million in 2002, and the cost of electric fuel and purchased power increased to $113 million in 2003 from $76 million in 2002. These changes were attributable to several factors, including the effect of the DWR's purchasing the net short position of SDG&E during 2002, higher electric commodity costs and volumes in 2003, and the increase in authorized 2003 distribution revenue. In addition, the increase in revenue was due to the recognition of $116 million related to the approved settlement of intermediate-term purchase power contracts and higher PBR awards during the third quarter or 2003.

Electric revenues decreased to $1.3 billion in 2002 from $1.7 billion in 2001, and the cost of electric fuel and purchased power decreased to $0.3 billion in 2002 from $0.8 billion in 2001. These decreases were primarily due to the DWR's purchasing SDG&E's net short position for a full year in 2002 and the effect of lower electric commodity costs and decreased off-system sales. For the fourth quarter, electric revenues increased to $320 million in 2002 from $284 million in 2001, and the cost of electric fuel and purchased power decreased to $76 million in 2002 from $87 million in 2001. The increase in electric revenues was due primarily to higher electric distribution and transmission revenue as well as additional revenues from the Incremental Cost Incentive Pricing (ICIP) mechanism, while the decrease in cost of electric fuel and purchased power was due primarily to a decrease in average electric commodity costs. Refer to Note 13 of the notes to Consolidated Financial Statements for further discussion of ICIP and SONGS.

The tables below summarize the California Utilities' natural gas and electric volumes and revenues by customer class for the years ended December 31, 2003, 2002 and 2001.

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

	Natural Gas Sales		Transportation & Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
2003:						
Residential	273	$ 2,479	2	$ 7	275	$ 2,486
Commercial and industrial	121	863	277	189	398	1,052
Electric generation plants	—	3	241	79	241	82
Wholesale	—	—	20	4	20	4
	394	$ 3,345	540	$ 279	934	3,624
Balancing accounts and other						386
Total						$ 4,010
2002:						
Residential	289	$ 2,089	2	$ 8	291	$ 2,097
Commercial and industrial	117	635	294	183	411	818
Electric generation plants	—	—	264	43	264	43
Wholesale	—	—	16	12	16	12
	406	$ 2,724				

~~576 $ 246 982 2,970 Balancing accounts and other 293~~
~~Total $ 3,263~~

~~2001: Residential 297 $ 2,797 2 $ 6 299 $ 2,803 Commercial and industrial 113 903 262 174 375 1,077 Electric generation plants~~ ~~417 104 417 104 Wholesale~~ ~~40 10 40 10~~

~~410 $ 3,700 721 $ 294 1,131 3,994 Balancing accounts and other 377~~
~~Total $ 4,371~~

~~ELECTRIC TRANSMISSION AND DISTRIBUTION (Dollars in millions, volumes in million kilowatt hours) 2003 2002 2001~~

~~Volumes Revenue Volumes Revenue Volumes Revenue~~

~~Residential 6,702 $ 731 6,266 $ 649 6,011 $ 775 Commercial 6,263 674 6,053 633 6,107 753 Industrial 1,976 161 1,883 160 2,792 325 Direct access 3,322 87 3,448 117 2,464 84~~

~~Street and highway lighting 91 11 88 9 89 10~~
~~Off system sales 8 5 413 88~~

~~18,362 1,664 17,743 1,568 17,876 2,035~~
~~Balancing and other 123 (286) (359)~~

~~Total $ 1,787 $ 1,282 $ 1,676~~

As explained in Note 13 of the notes to Consolidated Financial Statements, commodity-related revenues from the DWR's purchasing of SDG&E's net short position or from the DWR's allocated contracts are not included in revenue. However, the associated volumes and distribution revenue are included herein.

Other Operating Revenues and Cost of Sales. These tables provide a breakdown of other operating revenues and cost of sales by business unit.

(Dollars in millions)	2003	2002	2001
OPERATING REVENUES			
Sempra Energy Trading	$ 1,144	$ 821	$ 1,047
Sempra Energy Resources	671	349	178
Sempra Energy International	208	176	289
Sempra Energy Solutions	175	177	180
Total Global Enterprises	2,198	1,523	1,694
Parent and Other*	(108)	(20)	(11)
Total	$ 2,090	$ 1,503	$ 1,683
COST OF SALES			
Sempra Energy Trading	$ 542	$ 293	$ 320
Sempra Energy Resources	433	218	185
Sempra Energy International	166	148	257
Sempra Energy Solutions	65	56	92
Total Global Enterprises	1,206	715	854
Parent and Other*	(2)	(6)	19
Total	$ 1,204	$ 709	$ 873

*Includes certain intercompany eliminations recorded in consolidation.

For the fourth quarters of 2003 and 2002, revenues increased to $598 million from $409 million in 2002 and costs increased to $318 million from $206 million. These increases and the annual increases shown above were primarily due to higher revenues at SET as the result of increased volumes and volatility in the energy commodity markets, as well as increased revenues from SER's resumption of contract sales of electricity to the DWR in April 2002 and sales by its Twin Oaks power plant purchased in the fourth quarter of 2002.

The decreases in revenues and costs in 2002 from 2001 were primarily due to reduced SEI revenues as a result of decreased natural gas prices at its Mexican subsidiaries and lower activity at SET as a result of decreased volatility in energy commodity markets and lower energy commodity prices, partially offset by increased activity from acquisitions made during 2002. These decreases were partially offset by the increase in SER's sales to the DWR that commenced in June 2001 through September 2001 at below cost, and resumed in April 2002 at favorable contract rates under its long-term contract.

For the fourth quarters of 2002 and 2001, revenues increased to $409 million from $242 million in 2001 and costs increased to $206 million from $174 million. The increases were primarily due to increased activity at SET as a result of higher volatility in energy commodity markets as well as increased SER sales.

Other Operating Expenses. This table provides a breakdown of operating expenses by business unit.

(Dollars in millions)	2003	2002	2001
OPERATING EXPENSES			
California Utilities:			
Southern California Gas Company	$ 954	$ 872	$ 792
San Diego Gas & Electric	637	560	491
Total Utilities	1,591	1,432	1,283
Sempra Energy Trading	374	304	370
Sempra Energy Resources	93	44	21
Sempra Energy International	120	49	70
Sempra Energy Solutions	71	66	68
Total Global Enterprises	658	463	529
Parent and Other*	38	6	(52)
Total	$ 2,287	$ 1,901	$ 1,760

* Includes certain intercompany eliminations recorded in consolidation.

The increase at the California Utilities in 2003 from 2002 was primarily the result of a $75 million before-tax charge for litigation and for losses associated with a sublease of portions of the SoCalGas headquarters building, and increased labor and employee benefit costs. The non-recurring sublease losses pertain to pre-2003 transactions, but are charged against current operations because they are not material to annual financial statements. A smaller portion of the increase was due to the California fires, which primarily affected SDG&E and which are discussed in Note 14 of the notes to Consolidated Financial Statements. The fire costs are expected to be recovered in rates. General operating costs increased at SET due to the increased activity and a full year's activities for the businesses acquired in 2002, at SER due to the new power plants and at SEI due to the $77 million before-tax write-down of the carrying value of the assets of Frontier Energy, as described in Note 1 of the notes to Consolidated Financial Statements. In addition, operating costs increased due to a $24 million before-tax write-down of the carrying value of the assets of AEG and due to higher antitrust litigation costs at the Global companies. During 2002 the California Utilities recorded $23 million in litigation costs related to the California energy crisis.

For the 2003 and 2002 fourth quarters, other operating expenses increased to $656 million in 2003 ($474 million from the California Utilities) from $587 million in 2002 ($457 from the California Utilities). The increase was mainly due to increased operating costs at SDG&E, SET and SER as discussed above.

For the 2002 and 2001 fourth quarters, other operating expenses increased to $587 million from $394 million in 2001. This increase and the annual increase shown above was due primarily to increased operating costs at the California Utilities resulting largely from higher labor and employee benefits costs, litigation costs related to the California energy crisis, costs associated with SDG&E's nuclear generating facilities and balancing account costs at SoCalGas.

Other Income. Other income, primarily equity earnings from unconsolidated subsidiaries and interest on regulatory balancing accounts, was $26 million, $15 million and $3 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to increased equity earnings at SEI and other subsidiaries, and reduced balancing account interest expense, partially offset by lower operating results at SER's joint ventures resulting from business interruption insurance proceeds received in 2002 related to an outage at the El Dorado plant during 2001.

The increase in 2002 was primarily due to increased sales at the El Dorado power plant and the business interruption insurance proceeds, offset partially by lower 2002 equity earnings from international investments and the $19 million gain from SDG&E's sale of its property in Blythe, California in 2001.

Other income for the fourth quarter was a net loss of $12 million for 2003 compared to income of $9 million for 2002 and a loss of $12 million for 2001. The decrease in 2003 was due to decreased equity earnings from SEI as well as lower operating results at SER's joint ventures. The increase in 2002 was due primarily to lower net regulatory interest expense.

Interest Income. Interest income was $104 million, $42 million and $83 million in 2003, 2002 and 2001, respectively. $59 million of the increase in 2003 was due to the favorable resolution of income-tax issues with the Internal Revenue Service (IRS) in 2003. The decrease in 2002 compared to 2001 was due primarily to lower interest income on short-term investments.

Interest Expense. Interest expense was $308 million, $294 million and $323 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to the issuance of $1 billion of long-term notes in April 2002 and early 2003, and the reclassification of preferred dividends on mandatorily redeemable trust preferred securities and preferred stock of subsidiaries to interest expense as a result of the adoption of Statement of Financial Accounting Standards (SFAS) 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity," on July 1, 2003 (see Note 1 of the notes to Consolidated Financial Statements). These increases were offset partially by the paydown of commercial paper and debt maturities at the California Utilities.

The decrease in 2002 was primarily due to an increase in capitalized interest related to construction projects, lower interest rates and the favorable effects of interest rate swaps. Interest rates on certain of the company's debt can vary with credit ratings, as described in Notes 4 and 5 of the notes to Consolidated Financial Statements.

Interest expense for the fourth quarter was $85 million, $74 million and $63 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to the issuance of the $400 million of long-term notes, offset partially by the paydown of commercial paper and debt maturities at the California Utilities. The increase in 2002 was attributable to the issuance of $600 million of equity units by the company and $250 million of first mortgage bonds issued by SoCalGas, partially offset by debt maturities at the California Utilities.

Income Taxes. Income tax expense was $47 million, $146 million and $213 million in 2003, 2002 and 2001, respectively. The effective income tax rates were 6.3 percent, 20.2 percent and 29.1 percent, respectively. The changes in 2003 compared to 2002 were primarily due to the favorable resolution of income-tax issues in the fourth quarter of 2003 (which reduced income tax expense by $83 million) and a $39 million increase in income tax credits from synthetic fuel investments in 2003 (see discussion of Section 29 credits in Note 7), offset partially by a $25 million favorable resolution of income-tax issues at SDG&E in the second quarter of 2002. Income before taxes in 2003 included $59 million in interest income arising from the income tax settlement, resulting in an offsetting $24 million income tax expense. The decreases in income tax expense and in the effective income tax rates for 2002 compared to 2001 were primarily due to the favorable resolution of income-tax issues at SDG&E and increased income tax credits from synthetic fuel investments in 2002.

Income tax expense (benefit) for the fourth quarter was ($62) million in 2003 compared to $3 million in 2002, and ($40) million in 2001. The corresponding effective income tax (benefit) rates were (32.8) percent, 2.2 percent and (59.7) percent. The change in the 2003 quarter was due primarily to the resolution of the income-tax issues discussed above. The change in 2002 was due primarily to increased income before taxes, as well as the resolution in 2001 of prior-year tax issues. The low effective income tax rate in the 2002 quarter was primarily due to increased income tax credits from affordable-housing and synthetic fuel investments. These investments are discussed in Note 3 of the notes to Consolidated Financial Statements.

In connection with its affordable-housing investments, the company has unused tax credits dating back to 1999, which the company fully expects to utilize before their various expiration dates of 2019 to 2022. At December 31, 2003, the amount of these unused tax credits was $192 million. In addition, the company has $74 million of alternative minimum tax credits with no expiration date.

Net Income. Changes in net income between 2002 and 2003 are summarized in the table shown previously under "Overall Operations."

Excluding the effects of the $16 million extraordinary item in 2002 (see Note 1 of the notes to Consolidated Financial Statements), the increase in net income in 2002 compared to 2001 was primarily due to improved results at SER, lower interest expense, the 2001 after-tax charge of $25 million for the surrender of SEI's Nova Scotia natural gas distribution franchise and the effects of the income tax matters referred to above. These factors were partially offset by lower income in 2002 from SET and the $20 million after-tax gain on the sale of Energy America in 2001.

Net income for the fourth quarter of 2003 was $234 million, or $1.03 per diluted share of common stock in 2003, compared with $148 million, or $0.72 per diluted share of common stock in 2002, and $107 million, or $0.52 per diluted share of common stock in 2001. Net income for the fourth quarter of 2003 includes a $17 million charge for the cumulative effect of the change in accounting principle ($0.07 per diluted share of common stock). Net income for the fourth quarter of 2002 includes a $14 million extraordinary gain related to SET's acquisitions ($0.07 per diluted share of common stock). Excluding the cumulative effect of the accounting change and the extraordinary item, the increase in quarterly earnings in 2003 compared to 2002 was mainly due to the favorable resolution of income tax issues at the California Utilities in 2003. The increase in 2002 compared to 2001 was primarily attributable to increased earnings at SET (from increased volatility in the energy markets and the contribution from the metals business) and increased earnings at SER from the DWR contract, offset partially by decreased profitability from SEI's Argentine investments.

Book value per share was $17.17, $13.79 and $13.16, at December 31, 2003, 2002 and 2001, respectively. The increases in 2003 and 2002 were primarily the result of comprehensive income exceeding the dividends and, in 2003, the sale of additional shares of common stock for a per-share price in excess of its book value.

Net Income by Business Unit

(Dollars in millions)	2003	2002	2001
	Years ended December 31,		
California Utilities			
Southern California Gas Company	$ 209	$ 212	$ 207
San Diego Gas & Electric	334	203	177
Total Utilities	543	415	384
Global Enterprises			
Sempra Energy Trading	98	126	196
Sempra Energy Resources	94	60	(27)
Sempra Energy International	1	26	25
Sempra Energy Solutions	16	21	1
Total Global Enterprises	209	233	195
Sempra Energy Financial	41	36	28
Parent and Other*	(144)	(93)	(89)
Consolidated	$ 649	$ 591	$ 518

* Includes after-tax interest expense of $100 million, $70 million and $80 million in 2003, 2002 and 2001, respectively, and intercompany eliminations recorded in consolidation.

Southern California Gas Company

SoCalGas recorded net income of $209 million and $212 million in 2003 and 2002, respectively, and net income of $61 million and $45 million for the three-month periods ended December 31, 2003 and 2002, respectively. During 2003, net income was affected by the resolution of income-tax issues in the fourth quarter and the $29 million after-tax GCIM awards in the third quarter (see Note 14 of the notes to Consolidated Financial Statements for a discussion of GCIM awards), offset by a $32 million after-tax charge for litigation and for losses associated with a long-term sublease of portions of its headquarters building, and the end of sharing of merger savings (which positively impacted earnings by $17 million for the year ended December 31, 2002). The change for the quarter was due primarily to the resolution of the income-tax issues, offset partially by the end of sharing of merger savings (which positively impacted earnings by $4 million for the fourth quarter of 2002).

Net income for SoCalGas increased to $212 million in 2002 compared to $207 million in 2001 primarily due to decreased interest expense in 2002, offset partially by higher depreciation expense and the 2000 GCIM award recorded in 2001. Net income for the fourth quarter of 2002 decreased compared to the fourth quarter of 2001 due mainly to increased operating costs, partially offset by lower interest expense in 2002.

San Diego Gas & Electric

SDG&E recorded net income of $334 million and $203 million in 2003 and 2002, respectively, and net income of $128 million and $53 million for the fourth quarters of 2003 and 2002, respectively. The increase for the year was primarily due to the favorable resolution of income tax issues in the fourth quarter of 2003, which positively affected earnings by $79 million, income of $65 million after-tax related to the approved settlement of certain purchase power contracts (see Note 13 of the notes to Consolidated Financial Statements), higher earnings from PBR awards, and higher electric transmission and distribution revenue. These factors were partially offset by higher operating expenses, including litigation charges in the third quarter of 2003, the end of sharing of the merger savings (which positively impacted earnings by $8 million in 2002) and the $25 million favorable resolution of prior years' income-tax issues recorded in the second quarter of 2002. The change for the quarter was due to the resolution of the income tax issues and higher electric transmission and distribution revenue, offset partially by the end of sharing of the merger savings (which positively impacted earnings by $2 million for the 2002 quarter).

Net income increased to $203 million in 2002 from $177 million in 2001. The increase was primarily due to the $25 million after-tax benefit noted above and lower interest expense in 2002, partially offset by lower interest income in 2002 and the 2001 gain on the sale of SDG&E's Blythe property. Net income increased to $53 million for the fourth quarter of 2002, compared to $45 million for the corresponding period in 2001, primarily due to higher natural gas income, an increase in electric transmission and distribution revenues, and income tax adjustments in 2002, partially offset by the 2001 Blythe gain.

Sempra Energy Trading

SET recorded net income of $98 million in 2003 compared to $126 million and $196 million in 2002 and 2001, respectively. For the fourth quarter, SET recorded net income of $59 million in 2003 compared to $53 million and $10 million in 2002 and 2001, respectively. For purposes of comparison with the corresponding periods, net income for 2003 and 2002 would have been $117 million and $110 million if not for the repeal of Emerging Issues Task Force (EITF) 98-10 in 2003 and the extraordinary gain recognized in 2002, both discussed in Note 1 of the notes to Consolidated Financial Statements. The repeal of EITF 98-10 adversely impacted SET's results by a cumulative effect adjustment of $28 million and positively impacted earnings by $9 million related to operations in 2003, including a $12 million positive adjustment for the three months ended December 31, 2003.

The decrease in net income in 2002 compared to 2001 was primarily due to greater revenues in 2001 resulting from higher volatility in energy commodity markets during the first half of 2001, partially offset by the extraordinary gain of $16 million, earnings from new acquisitions and increased synthetic fuel credits in 2002.

SET's net income included the impact of its synthetic fuel credits of $73 million, $39 million and $28 million in 2003, 2002 and 2001, respectively (see Note 7 of the notes to Consolidated Financial Statements), which contributed $23 million, $11 million and $5 million to earnings in 2003, 2002 and 2001, respectively.

A summary of SET's net unrealized revenues for trading activities follows:

(Dollars in millions)	Years ended December 31, 2003	2002
Balance at beginning of period	$ 180	$ 405
Cumulative effect adjustment	(48)	--
Additions	755	442
Realized	(618)	(667)
Balance at end of year	$ 269	$ 180

The estimated fair values for SET's net unrealized trading assets as of December 31, 2003, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	Fair Market Value at December 31, 2003	Scheduled Maturity (in months) 0-12	13-24	25-36	>36
Prices actively quoted	$ 163	$ 84	$ 68	$(14)	$ 25
Prices provided by other external sources	(4)	(6)	(2)		4
Prices based on models and other valuation methods	22	5	2		15
Over the counter (OTC) revenue (1)	181	83	68	(14)	44
Exchange contracts (2)	88	19	57	8	4
Total	$ 269	$ 102	$ 125	$ (6)	$ 48

(1) The present value of net unrealized revenues to be received from outstanding OTC contracts.
(2) Cash received associated with open Exchange contracts.

Sempra Energy Resources

SER recorded net income of $94 million in 2003 and $60 million in 2002, compared to a net loss of $27 million in 2001. Net income for 2003 includes the cumulative effect of the change in accounting principle, which positively impacted SER's earnings by $9 million. See further discussion of this in Note 1 of the notes to Consolidated Financial Statements. Excluding this impact, the change in 2003 was primarily due to increased volumes under SER's contract with the DWR, offset by increased interest expense and start-up expenses related to SER's new power plants. The increase in earnings for 2002 was primarily due to SER's sales to the DWR that resumed in April 2002 at contract rates under its long-term contract, compared to 2001 sales which were at less than cost, and the recovery in 2002 of business interruption insurance related to an outage at the El Dorado plant in 2001. Losses in 2001 arose from development costs of new generation projects and from selling power to the DWR at below cost.

Sempra Energy International

Net income for SEI was $1 million, $26 million and $25 million for 2003, 2002 and 2001, respectively. The change in 2003 was primarily due to the $50 million after-tax impairment of the carrying value of long-lived assets at Frontier Energy (one of SEI's small U.S. utilities), partially offset by increased equity earnings from its South American joint ventures and a full year of earnings from the Gasaducto Bajanorte pipeline in Mexico, which began operations in September 2002. The increase for 2002 was primarily due to the after-tax charge of $25 million in 2001 following the surrender of the natural gas distribution franchise in Nova Scotia, partially offset by reduced profitability from SEI's Argentine subsidiaries in 2002. A discussion of the Argentine economic issue is included in Notes 1 and 3 of the notes to Consolidated Financial Statements.

Sempra Energy Solutions

SES recorded net income of $16 million in 2003, $21 million in 2002 and $1 million in 2001. The change in 2003 was primarily due to reduced profits from retail commodity sales, caused by higher wholesale energy prices' making it more difficult for non-utility energy suppliers to offer prices significantly below utility energy prices. The increase in net income from 2001 to 2002 was primarily due to increased commodity sales. In delivering electric and natural gas supplies to its commercial and industrial customers, SES hedges its price exposure through the use of exchange-traded and over-the-counter financial instruments. A summary of SES' net unrealized revenues from trading activities follows:

(Dollars in millions)	Years ended December 31, 2003	2002
Balance at beginning of period	$ 90	$ 55
Cumulative effect adjustment	(2)	--
Additions	75	90
Realized	(85)	(55)
Balance at end of year	$ 78	$ 90

The estimated fair values for SES' net unrealized trading assets as of December 31, 2003, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	Fair Market Value at December 31, 2003	Scheduled Maturity (in months) 0-12	13-24	25-36	>36
Exchange contracts	$ 1	$ 1	$ -	$ -	$ -
Prices actively quoted	77	44	18	10	5
Total	$ 78	$ 45	$ 18	$ 10	$ 5

Sempra Energy Financial

SEF recorded net income of $41 million in 2003, $36 million in 2002 and $28 million in 2001. The increase in 2003 was due to lower amortization expense, partially offset by increased equity losses from certain investments. The increase in 2002 was due to higher synthetic fuel (Section 29) income tax credits compared to 2001.

See discussion of Section 29 income tax credits in Note 7 of the notes to Consolidated Financial Statements. Whether SEF will invest in additional affordable-housing properties will depend on Sempra Energy's income tax position.

Parent and Other

Net losses for Parent and Other were $144 million, $93 million and $89 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to the $26 million negative after-tax impact of the cumulative effect of a change in accounting principle, the $21 million after-tax write down of the carrying value of the assets of AEG and higher interest expense as a result of the issuance of $1 billion of long-term notes in late 2002 and early 2003. The adoption of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities" and the resulting consolidation of AEG is discussed in Note 1 of the notes to Consolidated Financial Statements.

CAPITAL RESOURCES AND LIQUIDITY

The company's California Utility operations are the major source of liquidity. Funding of other business units' capital expenditures is significantly dependent on the California Utilities paying sufficient dividends to Sempra Energy and on liquidity requirements at SET, which fluctuate significantly.

At December 31, 2003, the company had $432 million in cash and $2.1 billion in available unused, committed lines of credit.

Management believes these amounts and cash flows from operations and new security issuances will be adequate to finance capital expenditure requirements (see Future Construction Expenditures and Investments for forecasted capital expenditures for the next five years), shareholder dividends, any new business acquisitions or start-ups, and other commitments. If cash flows from operations were to be significantly reduced or the company were to be unable to issue new securities under acceptable terms, neither of which is considered likely, the company would be required to reduce non-utility capital expenditures and investments in new businesses. Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activities in a manner consistent with its intention to maintain strong, investment-quality credit ratings.

At the California Utilities, cash flows from operations and from new and refunding debt issuances are expected to continue to be adequate to meet utility capital expenditure requirements and provide dividends to Sempra Energy. However, if SDG&E receives CPUC approval of its plans to purchase from SER a 550-megawatt (MW) generating facility to be constructed in Escondido, California, the level of SDG&E's dividends to Sempra Energy is expected to be significantly lower during the construction of the facility to enable SDG&E to increase its equity in preparation for the purchase of the completed facility. See Note 15 of the notes to Consolidated Financial Statements for additional discussion on the planned Palomar plant.

SET provides or requires cash as the level of its net trading assets fluctuates with prices, volumes, margin requirements (which are substantially affected by credit ratings and commodity price fluctuations) and the length of its various trading positions. Its status as a source or use of cash also varies with its level of borrowing from its own sources. SET's intercompany borrowings were $359 million at December 31, 2003, down from $418 million at December 31, 2002. SET's external debt was $115 million at December 31, 2002. There was no external debt outstanding at December 31, 2003. Company management continuously monitors the level of SET's cash requirements in light of the company's overall liquidity. Such monitoring includes the procedures discussed in "Market Risk."

SELNG will require funding for its planned development of LNG receiving facilities. While funding from the company is expected to be adequate for these requirements, the company may decide to use project financing if that is believed to be advantageous.

SER's projects are expected to be financed through a combination of project financing, SER's borrowings and funds from the company.

SEI is expected to require funding from the company and/or external sources to continue the expansion of its existing natural gas distribution operations in Mexico and its planned development of pipelines to serve LNG facilities expected to be developed in Baja California, Mexico and Hackberry, Louisiana.

In the longer term, SEF is expected to again be a net provider of cash through reductions of consolidated income tax payments resulting from its investments in affordable housing and synthetic fuel. However, that was not true in 2003 and will not be true in the near term, while the company is in an alternative minimum tax position.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $1.1 billion, $1.4 billion and $0.7 billion for 2003, 2002 and 2001, respectively.

The decrease in cash flows from operations in 2003 compared to 2002 was primarily attributable to a decrease in overcollected regulatory balancing accounts at the California Utilities, partially offset by higher accounts payable in 2003 primarily due to timing.

The increase in cash flows from operations in 2002 compared to 2001 was attributable to SDG&E's collection of balancing accounts (see Note 1 of the notes to Consolidated Financial Statements) and the change to a net income tax liability position at December 31, 2002 compared to a net income tax asset position at the end of 2001. In addition, cash flows from operations increased due to less growth in net trading assets and the payment of higher trade payables in 2001. These increases were partially offset by a decrease in deferred income taxes and investment tax credits and higher accounts receivable in 2002 resulting from an increase in SoCalGas' natural gas commodity costs for the fourth quarter of 2002 compared to the corresponding period in the prior year.

During 2003, the company made pension plan contributions of $27 million for the 2003 plan year. Contributions of $3 million were made in each of 2002 and 2001.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $1.3 billion, $1.7 billion and $1.0 billion for 2003, 2002 and 2001, respectively.

The decrease in cash used in investing activities in 2003 compared to 2002 was primarily due to lower capital expenditures for the Termoelectrica de Mexicali (TDM) power plant and lower investments in U.S. Treasury obligations made in connection with the Mesquite synthetic lease, higher distributions from investments in South America, and SET's higher acquisition activities in 2002.

The increase in cash used in investing activities in 2002 compared to 2001 was primarily due to increased capital expenditures, primarily at SER and the California Utilities, and SET's acquisition activities.

Expenditures for property, plant and equipment, and for those investments that effectively constitute similar expenditures, are presented in the following table.

(in millions)	
2003	$1,228
2002	$1,524
2001	$1,179
2000	$ 963
1999	$ 705

The 2002 amount is larger than the other years due to the construction of the SER power plants.

Capital Expenditures for Property, Plant and Equipment

Capital expenditures were $1.0 billion in 2003 compared with $1.2 billion in 2002 and $1.1 billion in 2001. The decrease in 2003 from 2002 was due primarily to lower capital expenditures for the TDM power plant.

The California Utilities

Capital expenditures for property, plant, and equipment by the California Utilities were $762 million in 2003 compared to $731 million in 2002 and $601 million in 2001. The increase in 2003 was primarily due to $40 million of capital costs associated with the Southern California wildfires in October 2003. The increase in 2002 was due to additions to SDG&E's natural gas and electric distribution systems, improvements to SoCalGas' distribution system, and expansion of pipeline capacity to meet increased demand by electric generators and by commercial and industrial customers.

Sempra Energy Resources

SER acquires, develops and operates power plants throughout the U.S. and Mexico. The following table lists the MW capacity of each power plant currently in operation. All of the plants are natural gas-fired combined-cycle facilities, except for Twin Oaks Power, which is coal-fired.

Power Plant	Generating Capacity	Location
Mesquite Power	1,250	Arlington, AZ
Termoelectrica De Mexicali	600	Mexicali, Mexico
Twin Oaks Power	305	Bremond, TX
Elk Hills Power (50% owned)	275*	Bakersfield, CA
El Dorado (50% owned)	240*	Boulder City, NV
Total MW in operation	2,670	

* SER's share

Other potential plants, including the Palomar plant, which is discussed above and in Note 15 of the notes to Consolidated Financial Statements, are in various stages of consideration, permitting or site-acquisition. Others have completed these stages but construction is awaiting market changes that will permit advance signing of long-term contracts at adequate margins.

In 2003, TDM commenced operations of its 600-MW, $350 million power plant near Mexicali, Baja California, Mexico. SER invested $34 million and $158 million in TDM in 2003 and 2002, respectively.

Operations also commenced in 2003 for the wholly owned 1,250-MW Mesquite Power plant, located near Phoenix, Arizona. Prior to 2004, this project was financed through a synthetic lease agreement. See further discussion of the consolidation of Mesquite Trust, the owner of Mesquite Power, in Note 1 of the notes to Consolidated Financial Statements. In January 2004, the company terminated the lease and purchased the assets of Mesquite Trust for $631 million.

Also in 2003, SER made turbine payments of $69 million for power plants under development.

In October 2002, SER purchased the 305-MW, coal-fired Twin Oaks power plant for $120 million.

See Note 2 of the notes to Consolidated Financial Statements for additional discussion on SER's recent power plant investments and acquisitions.

Sempra Energy LNG

In April 2003, SELNG completed its previously announced acquisition of the proposed Cameron LNG project from a subsidiary of Dynegy, Inc. In December 2003, SELNG and Shell International Gas Limited announced plans to form a 50/50 joint venture to build, own and operate Energia Costa Azul, an LNG receiving terminal in Baja California. In December 2003, SELNG signed a Heads of Agreement (HOA) for the supply of 500 million cubic feet of gas a day from Indonesia's Tangguh LNG liquefaction facility to Energia Costa Azul. The non-binding HOA is expected to be the precursor to a full 20-year purchase/supply agreement. In 2003, SELNG invested $42 million in Cameron LNG and $10 million in Energia Costa Azul. See Note 2 of the notes to Consolidated Financial Statements for additional discussion on the LNG projects.

Sempra Energy International

In 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with a pipeline built by PG&E Corporation that connects to Arizona. SEI invested $17 million, $37 million and $74 million in the pipeline in 2003, 2002 and 2001, respectively, for a total through December 31, 2003 of $128 million.

Three of SEI's Mexican subsidiaries build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. On February 7, 2003, SEI purchased the remaining minority interests in all of its Mexican subsidiaries. As a result, as of December 31, 2003, SEI owns 100 percent of all its Mexican subsidiaries. Through December 31, 2003, the distribution companies have made capital expenditures aggregating $127 million. Total capital expenditures for these subsidiaries were $15 million in both 2003 and 2002, and $19 million in 2001.

Sempra Energy Trading

In 2003, SET spent $27 million for the development of Bluewater Gas Storage, LLC. See Note 2 of the notes to Consolidated Financial Statements for further discussion.

Investments

Investments and acquisition costs were $202 million, $429 million and $111 million for 2003, 2002 and 2001, respectively. The decrease from 2003 to 2002 was due to lower investments in U.S. Treasury obligations made in connection with the Mesquite synthetic lease in 2003 and SET's higher acquisition activities in 2002. The increase in 2002 was due to the increase in requirements for the synthetic lease financing for the construction of the Mesquite Power plant and SET's acquisition of new businesses. For a discussion of the synthetic lease, see Note 2 of the notes to Consolidated Financial Statements.

Sempra Energy Trading

During 2002, SET completed acquisitions that added base metals trading and warehousing to its trading business. The purchase price of the 2002 acquisitions totaled $119 million, net of cash acquired. For additional discussion related to the SET acquisitions, see Note 2 of the notes to Consolidated Financial Statements.

Sempra Energy Resources

In July 2003, the 550-MW Elk Hills power plant near Bakersfield, California began commercial operations. Elk Hills, an unconsolidated subsidiary, is jointly owned with Occidental Energy Ventures Corporation (Occidental) and supplies electricity to California. During 2003, 2002 and 2001, SER invested $47 million, $39 million and $91 million, respectively. Information concerning litigation with Occidental is provided in Note 15 of the notes to Consolidated Financial Statements.

Other

See further discussion of investing activities, including the $197 million foreign currency exchange adjustment relating to Argentina, in Notes 2 and 3 of the notes to Consolidated Financial Statements.

Future Construction Expenditures and Investments

The company expects to make capital expenditures of $1.1 billion in 2004. Significant capital expenditures are expected to include $750 million for California utility plant improvements and $170 million for the development of the two LNG regasification terminals. These expenditures are expected to be financed by cash flows from operations and security issuances.

Over the next five years, the company expects to make capital expenditures of $4.4 billion at the California Utilities and has identified $2.1 billion of capital expenditures at the other subsidiaries, including the development of the LNG facilities and construction of power plants by SER. Both amounts include the Palomar plant (see Note 15 of the notes to Consolidated Financial Statements for further discussion) which would be constructed by SER and then purchased by SDG&E.

Construction, investment and financing programs are periodically reviewed and revised by the company in response to changes in economic conditions, competition, customer growth, inflation, customer rates, the cost of capital, and environmental and regulatory requirements. In addition, the excess of existing power plants and other energy-related facilities compared to market demand in certain regions of the country and/or the plants that are owned by companies in financial distress may provide the company with opportunities to acquire existing power plants instead of or in addition to new construction.

The company's level of construction expenditures and investments in the next few years may vary substantially, and will depend on the availability of financing and business opportunities providing desirable rates of return. The company intends to finance its capital expenditures in a manner that will maintain its strong investment-grade ratings and capital structure.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash provided by financing activities totaled $109 million, $138 million and $275 million for 2003, 2002 and 2001, respectively.

The cash provided by financing activities decreased in 2003 due to reduced long-term borrowings and higher repayments on long-term debt and short-term borrowings, partially offset by an increase in stock issuances.

Cash flows from financing activities decreased in 2002 from 2001 due primarily to the higher temporary drawdowns of lines of credit in 2001, partially offset by increased debt issuances in 2002.

Long-Term and Short-Term Debt

In 2003, the company issued $900 million in long-term debt, consisting of $400 million of senior unsecured notes and $500 million of first mortgage bonds issued by SoCalGas.

Repayments on long-term debt in 2003 included $100 million of the borrowings under a line of credit and $66 million of rate-reduction bonds. In 2003, SEF repaid $36 million of debt incurred to acquire limited partnership interests. Repayments also included $325 million of SoCalGas' first mortgage bonds. In addition, $70 million of SoCalGas' $75 million medium-term notes were put back to the company. The remaining $5 million matures in 2028.

In January 2004, SoCalGas optionally redeemed its $175 million 6.875% first mortgage bonds. Also in January 2004, SER purchased the assets of Mesquite Trust, thereby extinguishing $630 million of debt outstanding.

The net short-term debt reduction of $518 million in 2003 primarily consisted of the paydown of commercial paper.

In 2002, the company issued $1.2 billion in long-term debt, including $600 million of equity units at Sempra Energy and $250 million of 4.80% first mortgage bonds at SoCalGas. Each equity unit consists of $25 principal amount of the company's 5.60% senior notes due May 17, 2007 and a contract to purchase for $25 on May 17, 2005, between .8190 and ..9992 of a share of the company's common stock, with the precise number within that range to be determined by the then-prevailing market price. In addition, SER drew down $300 million against a line of credit to finance construction projects and acquisitions.

Repayments on long-term debt in 2002 of $479 million included $200 million borrowed under a line of credit, $138 million of first mortgage bonds and $66 million of rate-reduction bonds.

The net short-term debt reduction of $307 million in 2002 primarily consisted of the paydown of commercial paper.

Repayments on long-term debt in 2001 included $150 million of first mortgage bonds, $66 million of rate-reduction bonds and $120 million of unsecured debt.

The net short-term debt increase of $310 million in 2001 primarily represented borrowings through Global. Funds were used to finance construction costs of various power plant and pipeline projects in California, Arizona and Mexico.

In August 2003 Global replaced a $950 million revolving line of credit with two syndicated revolving credit agreements, permitting aggregate revolving credit borrowings of $1 billion. Global had no commercial paper outstanding at December 31, 2003 and $422 million of commercial paper, guaranteed by Sempra Energy, outstanding at December 31, 2002.

See Notes 1, 4 and 5 of the notes to Consolidated Financial Statements for further discussion of debt activity and lines of credit.

Capital Stock Transactions

On October 14, 2003, the company completed a common stock offering of 16.5 million shares priced at $28 per common share, resulting in net proceeds of $448 million. The proceeds were used primarily to pay off short-term debt.

In April and May of 2002, the company publicly offered and sold $600 million of "Equity Units," as discussed above.

Dividends

Dividends paid on common stock amounted to $207 million in 2003, $205 million in 2002 and $203 million in 2001.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The CPUC's regulation of the California Utilities' capital structure limits the amounts that are available for loans and dividends to the company from the California Utilities. At December 31, 2003, SDG&E and SoCalGas could have provided a total (combined loans and dividends) of $290 million and $175 million, respectively, to Sempra Energy. At December 31, 2003, SDG&E and SoCalGas had actual loans, net of payables, to Sempra Energy of $75 million and $21 million, respectively.

Capitalization

Total capitalization, including the current portion of long-term debt and excluding the rate-reduction bonds (which are non-recourse to the company) at December 31, 2003 was $9.1 billion. The debt-to-capitalization ratio was 55 percent at December 31, 2003. Significant changes in capitalization during 2003 included the October 2003 common stock offering, long-term borrowings and repayments, income and dividends.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2003. Trading liabilities are not included herein as such derivative transactions are primarily hedged against trading assets. In addition, liabilities reflecting fixed-price contracts and other derivatives are excluded as they are primarily offset against regulatory assets at the California Utilities. Additional information concerning commitments is provided above and in Notes 4, 5, 11 and 15 of the notes to Consolidated Financial Statements.

By Period (Dollars in millions) Description	2004	2005 and 2006	2007 and 2008	Thereafter	Total
Short term debt	$ 28	$ —	$ —	$ —	$ 28
Long term debt	1,433	499	690	2,652	5,274
Due to unconsolidated affiliates	—	—	62	300	362
Preferred stock of subsidiaries subject to mandatory redemption	1	3	20	--	24
Operating leases	97	162	145	213	617
Purchased power contracts	214	457	458	2,235	3,364
Natural gas contracts	988	358	46	207	1,599
Construction commitments	19	16	14	48	97
Twin Oaks coal supply	29	54	50	322	455
SONGS decommissioning	20	22	9	265	316
Asset retirement obligations	4	8	2	7	21
Environmental commitments	23	38	—	—	61
Other	—	—	20	55	75
Totals	$ 2,856	$ 1,617	$ 1,516	$ 6,304	$12,293

Credit Ratings

Several credit ratings of the company and its subsidiaries declined in 2003, but remain investment grade. As of January 31, 2004, credit ratings for Sempra Energy and its primary subsidiaries were as follows:

	S&P*	Moody's**	Fitch
SEMPRA ENERGY			
Unsecured debt	BBB+	Baa1	A
Trust preferred securities	BBB-	Baa2	A-
SDG&E			
Secured debt	A+	A1	AA
Unsecured debt	A-	A2	AA-
Preferred stock	BBB+	Baa1	A+
Commercial paper	A-1	P-1	F1+
SOCALGAS			
Secured debt	A+	A1	AA
Unsecured debt	A-	A2	AA-
Preferred stock	BBB+	Baa1	A+
Commercial paper	A-1	P-1	F1+
PACIFIC ENTERPRISES			
Preferred stock	BBB+	-	A
GLOBAL			
Unsecured debt guaranteed by Sempra Energy	-	Baa1	-
Commercial paper guaranteed by Sempra Energy	A-2	P-2	F1

* Standard & Poor's
** Moody's Investor Services, Inc.

As of January 31, 2004, the company has a stable outlook rating from all three credit rating agencies.

FACTORS INFLUENCING FUTURE PERFORMANCE

The California Utilities provide a generally stable base of earnings for the company. Earnings growth and variability results primarily from activities at SET, SER, SELNG and SEI. Developments and pending matters concerning the factors influencing future performance are summarized below. Notes 13, 14 and 15 of the notes to Consolidated Financial Statements describe events in the deregulation of California's electric and natural gas industries and various FERC, SET and income tax issues.

California Utilities

Electric Industry Restructuring and Electric Rates

Subsequent to the electric capacity shortages of 2000-2001, SDG&E's service territory had and continues to have an adequate supply of electricity. However, various projections of electricity demand in SDG&E's service territory indicate that, without additional electrical generation and transmission and reductions in electrical usage, beginning in 2005, electricity demand could begin to outstrip available resources. SDG&E has issued a request for proposals (RFP) to meet the electric capacity shortfall, estimated at 69 MW in 2005 and increasing annually by approximately 100 MW, and has filed a proposed plan at the CPUC for meeting these capacity requirements. See Note 13 of the notes to Consolidated Financial Statements for additional information regarding the RFP results.

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

See additional discussion of this and related topics, including the CPUC's adjustment to its plan for deregulation of electricity, in Note 13 of the notes to Consolidated Financial Statements.

Natural Gas Restructuring and Rates

In December 2001 the CPUC issued a decision related to natural gas industry restructuring; however, implementation has been delayed. A CPUC decision could be issued in the first quarter of 2004. With the California Utilities' natural gas supply contracts nearing expiration, the company believes that regulation needs to consider sufficiently the adequacy and diversity of supplies to California, transportation infrastructure and cost recovery thereof, hedging opportunities to reduce cost volatility, and programs to encourage and reward conservation. Additional information on natural gas industry restructuring is provided in Note 14 of the notes to Consolidated Financial Statements.

CPUC Investigation of Compliance with Affiliate Rules

On February 27, 2003, the CPUC opened an investigation of the business activities of SDG&E, SoCalGas and Sempra Energy to ensure that they have complied with statutes and CPUC decisions in the management, oversight and operations of their companies. In September 2003, the CPUC suspended the procedural schedule until it completes an independent audit to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of SDG&E and SoCalGas. The audit will cover years 1997 through 2003, is expected to commence in March 2004 and should be completed by the end of 2004. In accordance with existing CPUC requirements, the California Utilities' transactions with other Sempra Energy affiliates have been audited by an independent auditing firm each year, with results reported to the CPUC, and there have been no material adverse findings in those audits. Additional information on the CPUC's investigation is provided in Note 14 of the notes to Consolidated Financial Statements.

Cost of Service Filing

The California Utilities have filed cost of service applications with the CPUC, seeking rate increases designed to reflect forecasts of 2004 capital and operating costs. The California Utilities are requesting revenue increases of $121 million. On December 19, 2003, settlements were filed with the CPUC for SoCalGas and for SDG&E that, if approved, would resolve most of the cost of service issues. A CPUC decision is likely in the second quarter of 2004. The California Utilities have also filed for continuation through 2004 of existing PBR mechanisms for service quality and safety that would otherwise expire at the end of

2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but deferred action on applying any rewards or penalties for performance relative to these targets to a decision to be issued later in 2004 in a second phase of these applications. This is discussed in Note 14 of the notes to Consolidated Financial Statements.

Sempra Energy Global Enterprises

Electric-Generation Assets

As discussed in "Cash Flows From Investing Activities," the company has been involved in the development of several electric-generation projects that will significantly impact the company's future performance. SER has 2,670 MW (its share) of new generation in operation, including the 550-megawatt Elk Hills power project, the 1,250-megawatt Mesquite Power plant, the 600-megawatt TDM power plant, the 305-megawatt Twin Oaks power plant and the 480-megawatt El Dorado Energy. Except for Elk Hills, the plants' electricity is available for markets in California, Arizona, Texas and Mexico and may be used to supply power to California under SER's agreement with the DWR.

Investments

As discussed in "Cash Flows From Investing Activities" above, the company's investments will significantly impact the company's future performance. During 2002, SET completed acquisitions that added base metals trading and warehousing to its trading business. These acquisitions included Sempra Metals Limited and Henry Bath & Son Limited. In addition, SET acquired assets of Sempra Metals & Concentrates Corp. and the U.S. warehousing business of Henry Bath, Inc., and SER acquired the Twin Oaks Power plant.

SELNG is in the process of developing Energia Costa Azul, an LNG receiving terminal in Baja California, Mexico, and the Cameron LNG receiving terminal in Hackberry, Louisiana. This is discussed in Note 2 of the notes to Consolidated Financial Statements. The viability and future profitability of this business unit is dependent upon numerous factors, including the relative prices of natural gas in North America and from LNG suppliers located elsewhere, negotiating sale and supply contracts at adequate margins, and completing cost-effective construction of the required facilities.

The Argentine economic decline and government responses (including Argentina's unilateral, retroactive abrogation of utility agreements early in 2002) are continuing to adversely affect the company's investment in two Argentine utilities. In September 2002, SEI initiated proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its Argentine investments resulting from governmental actions. SEI has made a request for arbitration to the International Center for Settlement of Investment Disputes. Additional information regarding this proceeding and related insurance is provided in Note 3 of the notes to Consolidated Financial Statements.

MARKET RISK

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

The company has adopted corporate-wide policies governing its market risk management and trading activities. Assisted by the company's Energy Risk Management Group (ERMG), the company's Energy Risk Management Oversight Committee (ERMOC), consisting of senior officers, oversees company-wide energy risk management activities and monitors the results of trading activities to ensure compliance with the company's stated energy risk management and trading policies. Utility management receives daily information on positions and the ERMG receives information detailing positions creating market and credit risk from all company affiliates (on a delayed basis as to the California Utilities). The ERMG independently measures and reports the market and credit risk associated with these positions. In addition, all affiliates have groups that monitor energy price risk management and trading activities independently from the groups responsible for creating or actively managing these risks.

Along with other tools, the company uses Value at Risk (VaR) to measure its exposure to market risk. VaR is an estimate of the potential loss on a position or portfolio of positions over a specified holding period, based on normal market conditions and within a given statistical confidence interval. The company has adopted the variance/covariance methodology in its calculation of VaR, and uses both the 95-percent and 99-percent confidence intervals. VaR is calculated independently by the ERMG for all company affiliates. Historical volatilities and correlations between instruments and positions are used in the calculation.

Following is a summary of SET's trading VaR profile (using a one-day holding period) in millions of dollars:

	95%	99%
December 31, 2003	$ 2.6	$ 3.7
2003 average	$ 6.5	$ 9.2
December 31, 2002	$ 4.6	$ 6.5
2002 average	$ 6.2	$ 8.7

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

See the revenue recognition discussion in Notes 1 and 10 and the additional market risk information regarding derivative instruments in Note 10 of the notes to Consolidated Financial Statements.

The following discussion of the company's primary market risk exposures as of December 31, 2003 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 certain commodities. 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's various affiliates are exposed, in varying degrees, to price risk primarily in the petroleum, metals, 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 of each affiliate.

Sempra Energy Trading

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

Sempra Energy Solutions

SES derives a substantial portion of its revenue from delivering electric and natural gas supplies to its commercial and industrial customers. As a result, SES is exposed to price volatility in the related domestic markets. Its contracts are written in a manner intended to preserve margin and carry minimal market risk. Exchange-traded and over-the-counter instruments are used to hedge contracts. The derivatives and financial instruments used to hedge the transactions include swaps, forwards, futures, options or combinations thereof.

California Utilities

With respect to the California Utilities, market risk exposure is limited due to CPUC authorized rate recovery of commodity purchase, sale, intrastate transportation and storage activity. However, the California Utilities may, at times, be exposed to market risk as a result of SDG&E's natural gas PBR and electric procurement activities or SoCalGas' GCIM, which are discussed in Notes 13 and 14 of the notes to Consolidated Financial Statements. They manage their risk within the parameters of the company's market risk management and trading framework. As of December 31, 2003, the total VaR of the California Utilities' natural gas and electric positions was not material. In addition, if commodity prices rose too rapidly, it is likely that volumes would decline. This would increase the per-unit fixed costs, which could lead to further volume declines, leading to increased per-unit fixed costs and so forth.

Interest Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its long-term debt. The company historically has funded utility operations through long-term debt issues with fixed interest rates and these interest rates are recovered in utility rates. As a result, some recent debt offerings have used a combination of fixed-rate and floating-rate debt. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures when appropriate, based upon market conditions.

At December 31, 2003, the California Utilities had $1.8 billion of fixed-rate debt and $0.3 billion of variable-rate debt. Interest on fixed-rate utility debt is fully recovered in rates on a historical cost basis and interest on variable-rate debt is provided for in rates on a forecasted basis. At December 31, 2003, utility fixed-rate debt had a one-year VaR of $280 million and utility variable-rate debt had a one-year VaR of $11 million. Non-utility debt (fixed-rate and variable-rate) subject to VaR modeling totaled $2.6 billion at December 31, 2003, with a one-year VaR of $176 million.

At December 31, 2003, the notional amount of interest-rate swap transactions totaled $650 million. See Note 5 of the notes to Consolidated Financial Statements for further information regarding interest rate swap transactions.

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

Credit Risk

Credit risk is the risk of loss that would be incurred as a result of nonperformance by counterparties of their contractual obligations. As with market risk, the company has adopted corporate-wide policies governing the management of credit risk. Credit risk management is performed by the ERMG and the California Utility's credit department and overseen by the ERMOC. Using rigorous models, the groups continuously calculate current and potential credit risk to counterparties to monitor actual balances in comparison to approved limits. The company avoids concentration of counterparties whenever possible and management believes its credit policies with regard to counterparties significantly reduce overall credit risk. These policies include an evaluation of prospective counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty and other security such as lock-box liens and downgrade triggers. At December 31, 2003, SET had 17 customers that owed $20 million to $100 million each. The majority of these accounts related to amounts invoiced for delivered physical energy commodities and were settled within 30 days. The company believes that adequate reserves have been provided for counterparty nonperformance.

As described in Note 15 of the notes to Consolidated Financial Statements, SER has a contract with the DWR to supply up to 1,900 MW of power to the state over 10 years, beginning in 2001. This contract results in a significant potential nonperformance exposure with a single counterparty; however, this risk has been addressed and mitigated by the terms of the contract.

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

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

Foreign Currency Rate Risk

The company has investments in entities whose functional currency is not the U.S. dollar, which exposes the company to foreign exchange movements, primarily in Latin American currencies. As a result of the devaluation of the Argentine peso that began at the end of 2001, SEI has reduced the carrying value of its investment downward by a cumulative total of $197 million as of December 31, 2003. These non-cash adjustments continue to occur based on fluctuations in the Argentine peso and have not affected net income, but have affected other comprehensive income (loss) and accumulated other comprehensive income (loss). See further discussion in Note 3 of the notes to Consolidated Financial Statements.

In appropriate instances, the company may attempt to limit its exposure to changing foreign exchange rates through both operational and financial market actions. Financial actions may include entering into forward, option and swap contracts to hedge existing exposures, firm commitments and anticipated transactions. As of December 31, 2003, the company had no significant arrangements of this type.

CRITICAL ACCOUNTING POLICIES AND KEY NON-CASH PERFORMANCE INDICATORS

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

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

SFAS 5 "Accounting for Contingencies," establishes the amounts and timing of when the company provides for contingent losses. Details of the company's issues in this area are discussed in Note 15 of the notes to Consolidated Financial Statements.

SFAS 71 "Accounting for the Effects of Certain Types of Regulation," has a significant effect on the way the California Utilities record assets and liabilities, and the related revenues and expenses, that would not be recorded absent the principles contained in SFAS 71.

SFAS 109 "Accounting for Income Taxes," governs the way the company provide for income taxes. Details of the company's issues in this area are discussed in Note 7 of the notes to Consolidated Financial Statements.

SFAS 123 "Accounting for Stock-Based Compensation" and SFAS 148 "Accounting for Stock-Based Compensation - Transition and Disclosure," give companies the choice of recognizing a cost at the time of issuance of stock options or merely disclosing what that cost would have been and not recognizing it in its financial statements. The company, like most U.S. companies, has elected the disclosure option for all options that are so eligible. The effect of this is discussed in Note 1 of the notes to Consolidated Financial Statements.

SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" and SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," have a significant effect on the balance sheets of SET, SES and the California Utilities but have no significant effect on the California Utilities' income statements because of the principles contained in SFAS 71. The effect on SET's income statement is discussed in Note 10 of the notes to Consolidated Financial Statements.

EITF 02-3 "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," has a significant effect on the financial statements of SET and SES, both of which had been recording transactions in accordance with EITF Issue 98-10, which was eliminated by EITF Issue 02-3. However, most of the trading assets and liabilities of SET and SES will now be covered by SFAS 133, SFAS 138 and SFAS 149, which have a similar effect.

SFAS 52 "Foreign Currency Translation" is critical to the company's international operations and its application is materially affected by the company's treatment of certain loans to the Argentine affiliates as equity (based on expectations that repayment will not occur in the near future).

FIN 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51," is critical to the company's consolidation of variable interest entities (VIEs) in its financial statements. FIN 46 requires the company to consolidate VIEs for which it is the primary beneficiary, as defined, and deconsolidate any previously consolidated affiliates that do not meet the consolidation criteria of FIN 46. Sempra Energy has identified two VIEs for which FIN 46 deems it to be the primary beneficiary. One of the VIEs is the owner of the Mesquite Power plant. The other VIE relates to an investment in an unconsolidated subsidiary, AEG. Sempra Energy consolidated these entities in its financial statements at December 31, 2003. In accordance with FIN 46, the company deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. See further discussion in Note 1 of the notes to Consolidated Financial Statements.

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

The calculation of fair or realizable values (including the likelihood of fully realizing the value of the investments in Argentina under the Bilateral Investment Treaty and the realizable value of Frontier Energy and AEG, all of which are discussed in Note 1 of the notes to Consolidated Financial Statements).

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

The costs to be incurred in fulfilling certain contracts that have been marked to market.

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

The likelihood of recovery of various deferred tax assets.

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

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

As discussed elsewhere herein, the company uses exchange quotations or other third-party pricing to estimate fair values whenever possible. When no such data is available, it uses internally developed models and other techniques. The assumed collectibility of receivables considers the aging of the receivables, the creditworthiness of customers and the enforceability of contracts, where applicable. The assumed collectibility of regulatory assets considers legal and regulatory decisions involving the specific items or similar items. The assumed collectibility of other assets considers the nature of the item, the enforceability of contracts where applicable, the creditworthiness of the other parties and other factors. Costs to fulfill contracts that are carried at fair value are based on prior experience. Actuarial assumptions are based on the advice of the company's independent actuaries. The likelihood of deferred tax recovery is based on analyses of the deferred tax assets and the company's expectation of future financial and/or taxable income, based on its strategic planning.

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

Key non-cash performance indicators for the company's subsidiaries include numbers of customers, and quantities of natural gas and electricity sold for the California Utilities, and plant availability factors at SER's generating plants. SET does not use non-cash performance factors. Its key indicators are profit margins by product line and by geographic area. The California Utilities' information is provided in "Introduction" and "Results of Operations." For competitive reasons, SER does not disclose its plant availability factors, but considers them to be very good, except for the second unit at Mesquite, which just began generation in December 2003. The following tables provide the SET information.

Trading Margin (Dollars in millions)	Years ended December 31, 2003	2002
Geographical:		
North America	$ 366	$ 311
Europe/Asia	172	165
Total	$ 538	$ 476
Product Line:		
Gas	$ 141	$ 173
Power	69	89
Oil - Crude and Products	128	74
Metals	96	78
Other	104	62
Total	$ 538	$ 476

Other than its two small natural gas utilities in the eastern United States, SEI's only consolidated operations are in Mexico. The three local natural gas distribution utilities have increased their customer count to almost 100,000 and their sales volume to almost 50 million cubic feet per day in 2003. The two pipelines had sales volumes of almost 450 million cubic feet per day in 2003.

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had a significant effect on the company are SFAS 143, 144, 148, 149 and 150, FIN 45 and 46, and EITF 02-3. They are described in Note 1 of the notes to Consolidated Financial Statements. Pronouncements that could have a material effect on the company are described below.

EITF Issue 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": In accordance with the EITF's rescission of Issue 98-10, the company no longer recognizes energy-related contracts under mark-to-market accounting unless the contracts meet the requirements stated under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," and its successors, which is the case for a substantial majority of the company's contracts. Upon adoption of this consensus on January 1, 2003, the company recorded the initial effect of rescinding Issue 98-10 as a cumulative effect of a change in accounting principle, which reduced after-tax earnings by $29 million. This is further described in Note 1 of the notes to Consolidated Financial Statements.

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

SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities": SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS 133. Under SFAS 149 natural gas forward contracts that are subject to unplanned netting (see Note 1 of the notes to Consolidated Financial Statements) do not qualify for the normal purchases and normal sales exception. The company has determined that all natural gas contracts are subject to unplanned netting and as such, these contracts will be marked to market. In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 will be further marked to market. Implementation of SFAS 149 on July 1, 2003 did not have a material impact on reported net income.

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

Sempra Energy has identified two VIEs for which it is the primary beneficiary. One of the VIEs (the Mesquite Trust) is the owner of the Mesquite Power plant for which the company has a synthetic lease agreement as described in Note 2. The other VIE relates to the investment in AEG. Sempra Energy consolidated these entities in its financial statements at December 31, 2003.

In accordance with FIN 46, the company has deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. See further discussion regarding FIN 46 in Note 1 of the notes to Consolidated Financial Statements.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains statements that are not historical fact and constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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, national and international economic, competitive, political, legislative and regulatory conditions and developments; actions by the California Public Utilities Commission, the California Legislature, the California Department of Water Resources, environmental and other regulatory bodies in countries other than the United States, and the Federal Energy Regulatory Commission; capital market conditions, inflation rates, interest rates and exchange rates; energy and trading markets, including the timing and extent of changes in commodity prices; weather conditions and conservation efforts; war and terrorist attacks; business, regulatory and legal decisions; the status of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company's business described in this report and other reports filed by the company from time to time with the Securities and Exchange Commission.

FIVE YEAR SUMMARY

At December 31 or for the years ended December 31 (Dollars in millions except per share amounts)	2003	2002	2001	2000	1999
OPERATING REVENUES					
California utilities:					
Gas	$ 4,010	$ 3,263	$ 4,371	$ 3,305	$ 2,911
Electric	1,787	1,282	1,676	2,184	1,818
Other	2,090	1,503	1,683	1,271	631
Total	$ 7,887	$ 6,048	$ 7,730	$ 6,760	$ 5,360
Operating income	$ 939	$ 987	$ 997	$ 884	$ 763
Net income	$ 649	$ 591	$ 518	$ 429	$ 394
Net income per common share: Basic	$ 3.07	$ 2.88	$ 2.54	$ 2.06	$ 1.66
Diluted	$ 3.03	$ 2.87	$ 2.52	$ 2.06	$ 1.66
Dividends declared per common share	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.56
Return on common equity	19.3%	21.4%	19.5%	15.7%	13.4%
Effective income tax rate	6.3%	20.2%	29.1%	38.6%	31.2%
Price range of common shares	$ 30.90 - $	26.25 - $	28.61 - $		

~~24.88 $~~
~~26.00 22.25~~
~~15.50 17.31~~
~~16.19 17.13~~
~~AT DECEMBER~~
~~31 Current~~
~~assets $~~
~~7,886 $~~
~~7,010 $~~
~~4,790 $~~
~~6,525 $~~
~~3,090 Total~~
~~assets~~
~~$22,009~~
~~$20,242~~
~~$17,746~~
~~$17,850~~
~~$13,312~~
~~Current~~
~~liabilities~~
~~$ 8,348 $~~
~~7,247 $~~
~~5,472 $~~
~~7,490 $~~
~~3,236 Long-~~
~~term debt~~
~~(excludes~~
~~current~~
~~portion) $~~
~~3,841 $~~
~~4,083 $~~
~~3,436 $~~
~~3,268 $~~
~~2,902~~
~~Shareholders'~~
~~equity $~~
~~3,890 $~~
~~2,825 $~~
~~2,692 $~~
~~2,494 $~~
~~2,986 Common~~
~~shares~~
~~outstanding~~
~~(in~~
~~millions)~~
~~226.6 204.9~~
~~204.5 201.9~~
~~237.4 Book~~
~~value per~~
~~common share~~
~~$ 17.17 $~~
~~13.79 $~~
~~13.16 $~~
~~12.35 $~~
~~12.58~~

Statement of Management's Responsibility for the Consolidated Financial Statements

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles. The integrity and objectivity of these financial statements and the other financial information in the Financial Report, including the estimates and judgments on which they are based, are the responsibility of management. The financial statements have been audited by Deloitte & Touche LLP, independent auditors appointed by the audit committee of the board of directors. Their report is shown on the next page. Management has made available to Deloitte & Touche LLP all of the company's financial records and related data, as well as the minutes of shareholders' and directors' meetings.

Management maintains a system of internal control which it believes is adequate to provide reasonable, but not absolute, assurance that assets are properly safeguarded, that transactions are executed in accordance with management's authorization and are properly recorded, and that the accounting records may be relied on for the preparation of the consolidated financial statements, and for the prevention and detection of fraudulent financial reporting. The concept of reasonable assurance recognizes that the cost of a system of internal control should not exceed the benefits derived and that management makes estimates and judgments of these cost/benefit factors.

Management monitors compliance with the system of internal control through its own review and an internal auditing program, which independently assesses the effectiveness of the internal controls. The company's independent auditors also consider certain elements of internal controls in order to determine their audit procedures for the purpose of expressing an opinion on the company's financial statements. Management considers the recommendations of the internal auditors and independent auditors concerning the company's system of internal controls and takes appropriate actions. Management believes that the company's system of internal control is adequate to provide reasonable assurance that the accompanying financial statements present fairly the company's financial position and results of operations.

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

The board of directors has an audit committee, comprised of independent directors, to assist in fulfilling its oversight responsibilities for management's conduct of the company's financial reporting processes. The audit committee meets regularly to discuss financial reporting, internal controls and auditing matters with management, the company's internal auditors and the independent auditors, and recommends to the board of directors any appropriate response to those discussions. The audit committee appoints the independent auditors. The independent auditors and the internal auditors periodically meet alone with the audit committee and have free access to the audit committee at any time.

/S/ NEAL E. SCHMALE
Neal E. Schmale
Executive Vice President and
Chief Financial Officer

/S/ FRANK H. AULT
Frank H. Ault
Senior Vice President and
Controller

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Sempra Energy:

We have audited the accompanying consolidated balance sheets of Sempra Energy and subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related statements of consolidated income, cash flows and changes in shareholders' equity for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sempra Energy and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003, and Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities an interpretation of ARB No. 51, effective December 31, 2003.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 23, 2004

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME
(Dollars in millions, except per share amounts)
Years ended
December 31,
2003 2002
2001 -------
------- ----

~~OPERATING~~
~~REVENUES~~
~~California~~
~~utilities:~~
~~Natural gas~~
~~$ 4,010 $~~
~~3,263 $~~
~~4,371~~
~~Electric~~
~~1,787 1,282~~
~~1,676 Other~~
~~2,090 1,503~~
~~1,683~~
~~Total~~
~~7,887 6,048~~
~~7,730~~
~~OPERATING~~
~~EXPENSES~~
~~California~~
~~utilities:~~
~~Cost of~~
~~natural gas~~
~~2,071 1,381~~
~~2,549 Cost~~
~~of electric~~
~~fuel and~~
~~purchased~~
~~power 541~~
~~297 782~~
~~Other cost~~
~~of sales~~
~~1,204 709~~
~~873 Other~~
~~operating~~
~~expenses~~
~~2,287 1,901~~
~~1,760~~
~~Depreciation~~
~~and~~
~~amortization~~
~~615 596 579~~
~~Franchise~~
~~fees and~~
~~other taxes~~
~~230 177 190~~
~~Total 6,948~~
~~5,061 6,733~~
~~Operating~~
~~income 939~~
~~987 997~~
~~Other income~~
~~-- net 26 15~~
~~3 Interest~~
~~income 104~~
~~42 83~~
~~Interest~~
~~expense~~
~~(308) (294)~~
~~(323)~~
~~Preferred~~
~~dividends of~~
~~subsidiaries~~
~~(10) (11)~~
~~(11) Trust~~
~~preferred~~
~~distributions~~
~~by~~
~~subsidiary~~
~~(9) (18)~~
~~(18)~~
~~Income~~
~~before~~

~~income taxes 742 721 731~~

~~Income tax expense 47 146 213~~

~~Income before extraordinary item and cumulative effect of changes in accounting principles 695 575 518~~

~~Extraordinary item, net of tax (Note 1) 16~~

~~Income before cumulative effect of changes in accounting principles 695 591 518~~

~~Cumulative effect of changes in accounting principles, net of tax (Note 1) (46)~~

~~Net income $ 649 $ 591 $ 518~~

~~======= ======= =======~~

~~Weighted-average number of shares outstanding (thousands):~~

~~Basic 211,740 205,003 203,593~~

~~Diluted 214,482 206,062 205,338~~

~~Income before extraordinary item and cumulative effect of changes in accounting principles per share of common stock~~

~~Basic $ 3.29 $ 2.80 $ 2.54~~

~~Diluted $ 3.24 $ 2.79 $ 2.52~~

~~Income before cumulative effect of changes in accounting principles per share of common stock~~

~~Basic $ 3.29~~

~~$ 2.88 $ 2.54~~

~~Diluted $ 3.24 $ 2.87 $ 2.52~~

~~Net income per share of common stock Basic $ 3.07 $ 2.88 $ 2.54 --------~~

~~Diluted $ 3.03 $ 2.87 $ 2.52~~

~~Common dividends declared per share $ 1.00 $ 1.00 $ 1.00 ======= ======= ======= See notes to Consolidated Financial Statements.~~

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
December 31, -- --------------- -------- 2003 2002 ---------- ----------

~~ASSETS Current assets: Cash and cash equivalents $ 432 $ 455 Short-term investments 363 -- Accounts receivable - trade 1,012 754 Accounts and notes receivable - other 127 132 Interest receivable 62 3 Due from unconsolidated affiliates -- 80 Income taxes receivable 20 -- Deferred income taxes -- 20 Trading assets 5,250 5,064 Regulatory assets arising from fixed-price contracts and other derivatives 144 151 Other regulatory assets 89 75 Inventories 147 134 Other 240 142 ---------- ---------- Total current assets 7,886 7,010 ---------- ----------~~

~~Investments and other assets: Due from unconsolidated affiliates 55 57 Regulatory assets arising from fixed-price contracts and other derivatives 650 812 Other regulatory assets 554 532 Nuclear decommissioning trusts 570 494 Investments 1,114 1,313 Fixed-price contracts and other derivatives -- 42 Sundry 706 664 ---------- ---------- Total investments and other assets 3,649 3,914 ---------- ----------~~

~~Property, plant and equipment: Property, plant and equipment 15,317 13,816 Less accumulated depreciation and~~

~~amortization (4,843) (4,498)~~

~~Total property, plant and equipment — net 10,474 9,318~~

~~Total assets $22,009 $20,242~~

~~======= =======~~

~~See notes to Consolidated Financial Statements.~~

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2003	December 31, 2002
~~LIABILITIES AND SHAREHOLDERS' EQUITY~~		
~~Current liabilities:~~		
~~Short term debt~~	~~$ 28~~	~~$ 570~~
~~Accounts payable -- trade~~	~~815~~	~~694~~
~~Accounts payable -- other~~	~~64~~	~~50~~
~~Income taxes payable~~	~~--~~	~~22~~
~~Deferred income taxes~~	~~123~~	~~--~~
~~Trading liabilities~~	~~4,457~~	~~4,094~~
~~Dividends and interest payable~~	~~136~~	~~133~~
~~Regulatory balancing accounts -- net~~	~~424~~	~~578~~
~~Fixed price contracts and other derivatives~~	~~148~~	~~153~~
~~Current portion of long term debt~~	~~1,433~~	~~281~~
~~Other~~	~~720~~	~~672~~
~~Total current liabilities~~	~~8,348~~	~~7,247~~
~~Long term debt~~	~~3,841~~	~~4,083~~
~~Deferred credits and other liabilities:~~		
~~Due to unconsolidated affiliates~~	~~362~~	~~162~~
~~Customer advances for construction~~	~~89~~	~~91~~
~~Postretirement benefits other than pensions~~	~~131~~	~~136~~
~~Deferred income taxes~~	~~634~~	~~800~~
~~Deferred investment tax credits~~	~~84~~	~~90~~
~~Regulatory liabilities arising from cost of removal obligations~~	~~2,238~~	~~2,486~~

~~Regulatory liabilities arising from asset retirement obligations 281 — Other regulatory liabilities 108 121 Fixed price contracts and other derivatives 680 813 Asset retirement obligations 313 — Deferred credits and other 831 984~~

~~— Total deferred credits and other liabilities 5,751 5,683 —~~

~~— Preferred stock of subsidiaries 179 204 ——~~

~~Mandatorily redeemable trust preferred securities — 200 -------- -~~

~~Commitments and contingent liabilities (Note 15) SHAREHOLDERS' EQUITY Preferred stock (50 million shares authorized, none issued) — Common stock (750 million shares authorized; 227 million and 205 million shares outstanding at December 31, 2003 and December 31, 2002, respectively) 2,028 1,436 Retained earnings 2,298 1,861 Deferred compensation relating to ESOP (35) (33) Accumulated other comprehensive income (loss) (401) (439) —~~

~~— Total shareholders' equity 3,890 2,825 ——~~
~~------- Total liabilities and shareholders' equity $22,009~~

~~$20,242~~
~~=======~~
~~======= See notes to Consolidated Financial Statements.~~

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)
Years ended
December 31,
2003 2002
2001 -------
------- -----
-- ~~CASH FLOWS~~
~~FROM~~
~~OPERATING~~
~~ACTIVITIES~~
~~Net income $~~
~~649 $ 591 $~~
~~518~~
~~Adjustments~~
~~to reconcile~~
~~net income to~~
~~net cash~~
~~provided by~~
~~operating~~
~~activities:~~
~~Extraordinary~~
~~item, net of~~
~~tax -- (16) -~~
~~- Cumulative~~
~~effect of~~
~~changes in~~
~~accounting~~
~~principles 46~~
~~-- --~~
~~Depreciation~~
~~and~~
~~amortization~~
~~615 596 579~~
~~Foreign~~
~~currency loss~~
~~(gain) 8 (63)~~
~~-- Deferred~~
~~income taxes~~
~~and~~
~~investment~~
~~tax credits~~
~~(73) (92) 106~~
~~Non-cash rate~~
~~reduction~~
~~bond expense~~
~~68 82 66~~
~~Equity in~~
~~(income)~~
~~losses of~~
~~unconsolidated~~
~~affiliates~~
~~(8) 55 (12)~~
~~Impairment~~
~~losses 101 --~~
~~-- Loss~~
~~(gain) on~~
~~sale and~~
~~disposition~~
~~of assets 8~~
~~14 (14) Other~~
~~- net 2 (5) -~~
~~- Net changes~~
~~in other~~
~~working~~
~~capital~~
~~components~~
~~(224) 151~~
~~(203)~~
~~Customer~~
~~refunds paid~~
~~-- -- (127)~~
~~Changes in~~
~~other assets~~
~~(66) 87 (280)~~
~~Changes in~~
~~other~~
~~liabilities~~
~~(5) 40 99 ---~~
~~------------~~
~~-------- Net~~
~~cash provided~~
~~by operating~~
~~activities~~
~~1,121 1,440~~
~~732 ---------~~
~~-------------~~
~~- CASH FLOWS~~
~~FROM~~

~~INVESTING ACTIVITIES Expenditures for property, plant and equipment (1,049) (1,214) (1,068) Investments and acquisitions of subsidiaries, net of cash acquired (202) (429) (111) Dividends received from unconsolidated affiliates 72 11 80 Net proceeds from sale of assets 29 — 128 Loans to unconsolidated affiliates (99) (82) (57) Other — net (4) (14) (11)~~

~~Net cash used in investing activities (1,253) (1,728) (1,039)~~

~~CASH FLOWS FROM FINANCING ACTIVITIES Common dividends paid (207) (205) (203) Issuances of common stock 549 13 41 Repurchases of common stock (6) (16) (1) Issuances of long-term debt 900 1,150 675 Payments on long-term debt (601) (479) (681) Loan from unconsolidated affiliate — — 160 Increase (decrease) in short-term debt — net (518) (307) 310 Other — net (8) (18) (26)~~

~~Net cash provided by financing activities 109 138 275~~

~~Decrease in cash and cash equivalents (23) (150) (32) Cash and cash equivalents, January 1 455 605 637~~

~~Cash and cash equivalents, December 31 $ 432 $ 455 $ 605 ======= ======= =======~~

~~46 Years ended December 31, 2003 2002 2001~~

~~CHANGES IN OTHER WORKING CAPITAL COMPONENTS (Excluding cash and cash equivalents, and debt due within one year) Accounts and notes receivable $ (231) $ (121) $ 353 Net trading assets 81 66 (362) Income taxes - net 6 86 (121) Inventories (13) (11) 33 Regulatory balancing accounts (156) 170 88 Regulatory assets and liabilities (30) 1 39 Other current assets (8) 51 33 Accounts payable 98 (103) (302) Other current liabilities 29 12 36~~

~~Net changes in other working capital components $ (224) $ 151 $ (203) ======= ======= ======= SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION Interest payments, net of amounts capitalized $ 296 $ 279 $ 302 ======= ======= ======= Income tax payments, net of refunds $ 118 $ 140 $ 138 ======= ======= ======= SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES Acquisition of subsidiaries: Assets acquired $ --~~

~~$ 1,134 $ --~~
~~Cash paid, net of cash acquired --~~
~~(119)~~

~~Liabilities assumed $ --~~
~~$ 1,015 $ --~~
~~=======~~
~~=======~~
~~=======~~
~~Consolidation of variable interest entities:~~
~~Assets recorded $ 820 $ $ --~~
~~Liabilities recorded (881)~~

~~Total $ (61) $ -- $ --~~
~~=======~~
~~=======~~
~~======= See notes to Consolidated Financial Statements.~~

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2003, 2002 and 2001
(Dollars in millions)
Deferred
Accumulated
Compensation
Other Total
Comprehensive
Common
Retained
Relating
Comprehensive
Shareholders'
Income Stock
Earnings to
ESOP Income
(Loss) Equity
- -----------

----- ~~Balance at December 31, 2000 $1,420 $1,162 $ (39) $ (49) $2,494 Net income $518 518 518 Comprehensive income adjustments: Foreign currency translation losses (Note 1) (186) (186) (186) Pension (7) (7) (7)~~
~~Comprehensive income $325 ===== Common stock dividends declared (205) (205) Quasi-reorganization adjustment (Note 1) 35 35 Sale of common stock 41 41 Repurchase of common stock (1) (1) Common stock released from ESOP 3 3~~
~~Balance at December 31, 2001 1,495 1,475 (36) (242) 2,692 Net income $591 591 591 Comprehensive income adjustments: Foreign currency translation losses (Note 1) (162) (162) (162) Pension (35) (35) (35)~~
~~Comprehensive income $394~~

===== Common stock dividends declared (205) (205) Issuance of equity units (Note 5) (61) (61) Sale of common stock 18 18 Repurchase of common stock (16) (16) Common stock released from ESOP 3 3 ------ ------------- ------------- ------------- ------------

Balance at December 31, 2002 1,436 1,861 (33) (439) 2,825 Net income $649 649 649 Comprehensive income adjustments: Foreign currency translation gains (Note 1) 57 57 57 Pension (16) (16) (16) SFAS 133 (3) (3) (3) ------ Comprehensive income $687 ===== Common stock dividends declared (212) (212) Equity units adjustment 6 6 Quasi-reorganization adjustment (Note 1) 19 19 Sale of common stock 566 566 Repurchase of common stock (6) (6) Common stock released from ESOP 7 (2) 5 ------------- ------------- ------------- -------------

------ Balance at December 31, 2003 $2,028 $2,298 $ (35) $ (401) $3,890 ------------- ------------- ------------- ------------- ------------- ------------- -------------

------ See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Sempra Energy (the company) and all majority-owned subsidiaries. Investments in affiliated companies over which Sempra Energy has the ability to exercise significant influence, but not control, are accounted for using the equity method. All material intercompany accounts and transactions have been eliminated.

Quasi-Reorganization

In 1993, Pacific Enterprises (PE) divested substantially all of its non-utility business and effected a quasi-reorganization for financial reporting purposes as of December 31, 1992. Certain of the liabilities established in connection with the quasi-reorganization, including various income-tax issues, were favorably resolved, resulting in restoring $35 million and $19 million to shareholders' equity in 2001 and 2003, respectively. These restorations did not affect the calculation of net income or comprehensive income. The remaining liabilities will be resolved in future years and management believes the provisions established for these matters are adequate.

Use of Estimates in the Preparation of the Financial Statements

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

Basis of Presentation

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

Regulatory Matters

Effects of Regulation

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

The California Utilities prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation," under which a regulated utility records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. Regulatory liabilities represent reductions in future rates for amounts due to 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 and liabilities would be written off. In addition, SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" requires that a loss must be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase. Information concerning regulatory assets and liabilities is described in "Revenues," "Regulatory Balancing Accounts," and "Regulatory Assets and Liabilities."

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2003, represent net payables (payables net of receivables) of $86 million and $338 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 2002 were net payables of $184 million and $394 million. The payables normally are returned by reducing future rates.

Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. However, fluctuations in most operating and maintenance costs affect earnings. In addition, fluctuations in consumption levels affect earnings at SDG&E. The CPUC approved 100 percent balancing account treatment for variances between forecast and actual for SoCalGas' noncore revenues and throughput, eliminating the impact on earnings from any throughput and revenue variances from adopted forecast levels. Additional information on regulatory matters is included in Notes 13 and 14.

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)	2003	2002
SDG&E		
Fixed-price contracts and other derivatives	$ 560	$ 636
Recapture of temporary rate reduction*	259	326
Deferred taxes recoverable in rates	273	190
Unamortized loss on retirement of debt - net	44	49
Employee benefit costs	35	35
Cost of removal obligations**	(846)	(1,162)
Asset retirement obligations**	(303)	--
Other	24	7
Total	46	81
SoCalGas		
Fixed-price contracts and other derivatives	233	325
Environmental remediation	44	43
Unamortized loss on retirement of debt - net	45	38
Cost of removal obligation**	(1,392)	(1,324)
Deferred taxes refundable in rates	(192)	(164)
Employee benefit costs	(77)	(142)
Other	8	8
Total	(1,331)	(1,216)
PE - Employee benefit costs	72	80
Total PE consolidated	(1,259)	(1,136)
Total	$(1,213)	$(1,055)

* In connection with electric industry restructuring, which is described in Note 13, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2007.

** See discussion of SFAS 143 in "New Accounting Standards."

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

(Dollars in millions)	2003	2002
Current regulatory assets	$ 233	$ 226
Noncurrent regulatory assets	1,204	1,344
Current regulatory liabilities*	(23)	(18)
Noncurrent regulatory liabilities	(2,627)	(2,607)
Total	$(1,213)	$(1,055)

* Amount is included in Other Current Liabilities.

All of the 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 $19 million, $12 million and $22 million at December 31, 2003, 2002 and 2001, respectively. The company recorded a provision for doubtful accounts of $5 million, $13 million and $21 million in 2003, 2002 and 2001, respectively.

The allowance for realization of trading assets was $67 million, $86 million and $23 million, at December 31, 2003, 2002 and 2001, respectively. The company recorded a provision (reduction thereof) for trading assets of ($4) million, $20 million and $15 million in 2003, 2002 and 2001, respectively.

Trading Instruments

Trading assets and trading liabilities include option premiums paid and received; unrealized gains and losses from exchange-traded futures and options, over-the-counter (OTC) swaps, forwards, physical commodities and options; and base metals. Trading instruments are recorded by Sempra Energy Trading (SET) and Sempra Energy Solutions (SES) on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value. Unrealized gains and losses on OTC transactions reflect amounts which would be received from or paid to a third party upon net settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable netting arrangement. Additionally, as a result of SET's acquisitions in 2002, the company acquired $0.8 billion of base metals inventory. As of December 31, 2003 and 2002, trading assets included commodity inventory of $1.4 billion and $2.0 billion, respectively.

In October 2002, the Emerging Issues Task Force (EITF) rescinded fair value accounting for recording energy-trading activities and required contracts subsequently entered into to be accounted for at historical cost or the lower of cost or market, unless the contracts meet the requirements for fair value accounting under SFAS 133 and 149 (see below in "New Accounting Standards"). Energy transportation and storage contracts are recorded at cost. Energy commodity inventory is being recorded at the lower of cost or market. The company's base metals and concentrates inventory continue to be recorded at fair value in accordance with Accounting Research Bulletin (ARB) No. 43 "Restatement and Revision of Accounting Research Bulletins." See further discussion of EITF Issue 02-3 below in "New Accounting Standards."

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and carried at current market value based on current closing exchange quotations. Derivative commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and carried at fair value derived from current dealer quotations and underlying commodity-exchange quotations. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates. For long-dated forward transactions, current market values are derived using internally developed valuation methodologies based on available market information. When there is an absence of observable market data at inception, the value of the transaction is its cost. Where market rates are not quoted, current interest, commodity and volatility rates are estimated by reference to current market levels. Given the nature, size and timing of transactions, estimated values may differ significantly from realized values. Changes in market values are reflected in net income. Although trading instruments may have scheduled maturities in excess of one year, the actual settlement of these transactions can occur sooner, resulting in the current classification of trading assets and liabilities on the Consolidated Balance Sheets. "New Accounting Standards" below provides a discussion of the rescission of EITF 98-10.

Inventories

At December 31, 2003, inventory shown on the Consolidated Balance Sheets, which does not include amounts included in trading assets, included natural gas of $89 million and materials and supplies of $58 million. The corresponding balances at December 31, 2002 were $77 million and $57 million, respectively. Natural gas at the California Utilities ($84 million and $74 million at December 31, 2003 and 2002, respectively) is valued by the last-in first-out (LIFO) method. When the California Utilities' inventory is consumed, differences between the LIFO valuation and replacement cost are reflected in customer rates. Materials and supplies at the California Utilities are generally valued at the lower of average cost or market.

Property, Plant and Equipment

Property, plant and equipment primarily represents the buildings, equipment and other facilities used by the California Utilities to provide natural gas and electric utility services, and the newly constructed power plants at Sempra Energy Resources (SER).

The cost of plant includes labor, materials, contract services and related items. In addition, the cost of utility plant includes an allowance for funds used during construction (AFUDC). The cost of non-utility plant includes capitalized interest. 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 years ended December 31		
(Dollars in billions)	2003	2002	2003	2002	2001
California Utilities:					
Natural gas operations	$ 8.0	$ 7.7	4.28%	4.25%	4.25%
Electric distribution	3.2	3.0	4.70%	4.66%	4.67%
Electric transmission	0.9	0.9	3.09%	3.17%	3.19%
Other electric	0.7	0.6	9.53%	9.37%	8.46%
Total	12.8	12.2			
Other operations	2.5	1.6	various	various	various
Total	$ 15.3	$ 13.8			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $3.1 billion and $1.4 billion, respectively, at December 31, 2003, and were $2.9 billion and $1.3 billion, respectively, at December 31, 2002. See discussion of SFAS 143 under "New Accounting Standards." Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. See Note 13 for discussion of the sale of generation facilities and industry restructuring. Maintenance costs are expensed as incurred.

AFUDC, which represents the cost of funds used to finance the construction of utility plant, is added to the cost of utility plant. AFUDC also increases income, partly as an offset to interest charges and partly as a component of Other Income - Net, in the Statements of Consolidated Income, although it is not a current source of cash. AFUDC amounted to $29 million, $34 million and $17 million for 2003, 2002 and 2001, respectively. Total capitalized carrying costs, including AFUDC and the impact of SER's construction projects, were $55 million, $63 million and $28 million for 2003, 2002 and 2001, respectively.

Long-Lived Assets

The company periodically evaluates whether events or circumstances have occurred that may affect the recoverability or the estimated useful lives of long-lived assets. Impairment occurs when the estimated future undiscounted cash flows are less than the carrying amount of the assets. If that comparison indicates that the assets' carrying value may be permanently impaired, the potential impairment is measured based on the difference between the carrying amount and the fair value of the assets based on quoted market prices or, if market prices are not available, on the estimated discounted cash flows. This calculation is performed at the lowest level for which separately identifiable cash flows exist. See further discussion of SFAS 144 in "New Accounting Standards." During the third and fourth quarters of 2003, the company recorded impairment charges of $77 million and $24 million to write down the carrying value of the assets of Frontier Energy and Atlantic Electric & Gas Limited (AEG), respectively. This is discussed further in "New Accounting Standards" below.

Nuclear Decommissioning Liability

At December 31, 2002, in accordance with SFAS 71, SDG&E had recorded a $355 million regulatory liability representing SDG&E's share of the estimated future decommissioning costs of the San Onofre Nuclear Generating Station (SONGS). In addition, Deferred Credits and Other Liabilities included $139 million of accrued decommissioning costs associated with SONGS. As of December 31, 2003, as the result of implementing SFAS 143, "Accounting for Asset Retirement Obligations," SDG&E had asset retirement obligations and related regulatory liabilities of $316 million and $303 million, respectively. Additional information on SONGS decommissioning costs is included below in "New Accounting Standards."

Legal Fees

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

Comprehensive Income

Comprehensive income includes all changes, except those resulting from investments by owners and distributions to owners, in the equity of a business enterprise from transactions and other events, including foreign-currency translation adjustments, minimum pension liability adjustments, and certain hedging activities. The components of other comprehensive income are shown in the Statements of Consolidated Changes in Shareholders' Equity.

Stock-Based Compensation

The company has stock-based employee compensation plans, which are described in Note 9. The company accounts for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees," and related Interpretations. For certain grants, no stock-based employee compensation cost is reflected in net income, since the options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. See "New Accounting Standards" below for further discussion. The following table provides the pro forma effects of recognizing compensation expense in accordance with SFAS 123, "Accounting for Stock-Based Compensation":

Years ended December 31,	2003	2002	2001
Net income as reported	$ 649	$ 591	$ 518
Stock-based employee compensation expense included in the computation of net income, net of tax	13	3	7
Total stock-based employee compensation under fair value method for all awards, net of tax	(20)	(11)	(8)
Pro forma net income	$ 642	$ 583	$ 517
Earnings per share: Basic--as reported	$ 3.07	$ 2.88	$ 2.54
Basic--pro forma	$ 3.03	$ 2.84	$ 2.54
Diluted--as reported	$ 3.03	$ 2.87	$ 2.52
Diluted--pro forma	$ 2.99	$ 2.83	$ 2.52

Revenues

Revenues of the California Utilities are primarily derived from deliveries of electricity and natural gas to customers and changes in related regulatory balancing accounts. Revenues from electricity and natural gas sales and services are generally recorded under the accrual method and recognized upon delivery. The portion of SDG&E's electric commodity that was procured for its customers by the California Department of Water Resources (DWR) and delivered by SDG&E is not included in SDG&E's revenues or costs. For 2001, California Power Exchange (PX) and Independent System Operator (ISO) power revenues have been netted against purchased-power expense to avoid double-counting of power sold into and then repurchased from the PX/ISO. During 2003, costs associated with long-term contracts allocated to SDG&E from the DWR were also not included in the Statements of Consolidated Income, since the

DWR retains legal and financial responsibility for these contracts. Refer to Note 13 for a discussion of the electric industry restructuring. Natural gas storage contract revenues are accrued on a monthly basis and reflect reservation, storage and injection charges in accordance with negotiated agreements, which have terms of up to three years. Operating revenue includes amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

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

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

SET generates a substantial portion of its revenues from market making and trading activities, as a principal, in natural gas, electricity, petroleum, metals and other commodities, for which it quotes bid and ask prices to end users and other market makers. Principal transaction revenues are recognized on a trade-date basis, and include realized gains and losses, and the net change in the fair value of unrealized gains and losses. SET also earns trading profits as a dealer by structuring and executing transactions. SET utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and volatile fluctuations. These instruments include futures, forwards, swaps and options. Options, which are either exchange-traded or directly negotiated between counterparties, provide the holder with the right to buy from or sell to the other party an agreed amount of a commodity at a specified price within a specified period or at a specified time.

As a writer of options, SET generally receives an option premium and then manages the risk of an unfavorable change in the value of the underlying commodity by entering into related transactions or by other means. Forward and future transactions are contracts for delivery of commodities in which the counterparty agrees to make or take delivery at a specified price. Commodity swap transactions may involve the exchange of fixed and floating payment obligations without the exchange of the underlying commodity. SET's financial instruments represent contracts with counterparties whereby payments are linked to or derived from market indices or on terms predetermined by the contract.

Non-derivative contracts are being carried at cost and accounted for on an accrual basis. Hence, the related profit or loss will be recognized as the contract is performed. Derivative instruments are discussed further in Note 10.

Revenues of SES are generated from commodity sales and energy-related products and services to commercial, industrial, government and institutional markets. Energy supply revenues from natural gas and electricity commodity sales are recognized on a current fair value basis and include realized gains and losses and the net change in unrealized gains and losses measured at fair value. Revenues on construction projects are recognized during the construction period using the percentage-of-completion method, and revenues from other operating and maintenance service contracts are recorded under the accrual method and recognized as service is rendered.

SET and SES record revenues from trading activities on a net basis in accordance with EITF 02-3. See further discussion of this matter and the rescission of EITF 98-10 under "New Accounting Standards."

Revenues of SER are derived primarily from the sale of electric energy to governmental and wholesale power marketing entities, which are recognized in accordance with provisions of EITF 91-6, "Revenue Recognition of Long-term Power Supply Contracts," and EITF 96-17, "Revenue Recognition Under Long-term Power Sales Contacts that Contain Both Fixed and Variable Terms." During 2003 and 2002, electric energy sales to the DWR accounted for a significant portion of total SER revenues.

The consolidated foreign subsidiaries of Sempra Energy International (SEI), all of which operate in Mexico, recognize revenue similarly to the California Utilities, except that SFAS 71 is not applicable due to the different regulatory environment.

Extraordinary Gain

During 2002, SET acquired two businesses for amounts less than the fair values of the business' net assets. In accordance with SFAS 141, "Business Combinations," those differences were recorded as extraordinary income. The $16 million of extraordinary income was recorded in the second quarter ($2 million) and in the fourth quarter ($14 million).

Foreign Currency Translation

The assets and liabilities of the company's foreign operations are generally translated into U.S. dollars at current exchange rates, and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments do not enter into the calculation of net income or retained earnings, but are reflected in comprehensive income and accumulated other comprehensive income, a component of shareholders' equity, as described below. Foreign currency transaction gains and losses are included in consolidated net income. To reflect the fluctuation in the Argentine peso, the functional currency of the company's Argentine operations, SEI adjusted its investment in its two Argentine natural gas utility holding companies upward by $26 million and downward by $102 million in 2003 and 2002, respectively. These non-cash adjustments did not affect net income, but did increase or reduce comprehensive income and accumulated other comprehensive income (loss). Smaller adjustments have been made to operations in other countries. Additional information concerning these investments is described in Note 3.

Transactions with Affiliates

Loans to Unconsolidated Affiliates

In December 2001, SEI issued two U.S. dollar denominated loans totaling $35 million and $22 million to its affiliates Camuzzi Gas Pampeana S. A. and Camuzzi Gas del Sur S. A., respectively. These loans have variable interest rates (8.168% at December 31, 2003) and are due on March 13, 2004. The total balance outstanding under the notes was $55 million and $56 million at December 31, 2003 and 2002, respectively. At December 31, 2003, this amount is included in non-current assets, under the caption Due from Unconsolidated Affiliates because they will be refinanced on longer terms.

Additionally, at December 31, 2002, SET had $79 million due from AEG and the company had $1 million due from other affiliates. At December 31, 2002, the outstanding loans are included in current assets under the caption Due from Unconsolidated Affiliates. In addition, SET had $44 million of trading assets due from AEG at December 31, 2002. At December 31, 2003, as a result of the adoption of FASB Interpretation No. (FIN) 46, AEG was consolidated. See "New Accounting Standards" below for a discussion of FIN 46.

Loans from Unconsolidated Affiliates

At both December 31, 2003 and 2002, SEI had long-term notes payable to affiliates which include $60 million at 6.47% due April 1, 2008 and $100 million at 6.62% due April 1, 2011. The loans are due to Chilquinta Energia Finance, LLC and are secured by SEI's investments in Chilquinta Energia S.A. and Luz del Sur S.A.A. (Luz del Sur) (See Note 3).

The company also reclassified $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates as a result of the adoption of FIN 46 effective December 31, 2003. In addition, dividend payments required on these instruments, previously recorded to Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded to Interest Expense for the last six months of 2003 on the company's Statements of Consolidated Income, in accordance with SFAS 150. See discussion of SFAS 150 in "New Accounting Standards" below.

Revenues and Expenses with Unconsolidated Affiliates

During 2003 and 2002 SER recorded $61 million and $39 million, respectively, in sales to El Dorado, an unconsolidated affiliate, and recorded $69 million and $49 million, respectively, of purchases for those same years.

New Accounting Standards

SFAS 132 (revised 2003), "Employers Disclosures about Pensions and Other Postretirement Benefits": This statement revised employers' disclosures about pension plans and other postretirement benefit plans. It requires disclosures beyond those in the original SFAS 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement plans. It does not change the measurement or recognition of those plans. This statement is effective for financial statements with fiscal years ending after December 15, 2003.

SFAS 142, "Goodwill and Other Intangible Assets": In July 2001, the FASB issued SFAS 142, which provides guidance on how to account for goodwill and other intangible assets after an acquisition is complete. SFAS 142 calls for amortization of goodwill to cease and requires goodwill and certain other intangibles to be tested for impairment at least annually. Amortization of goodwill, including the company's share of amounts recorded by unconsolidated subsidiaries, was $24 million in 2001. In accordance with the transitional guidance of SFAS 142, recorded goodwill attributable to the company was tested for impairment in 2002 by comparing the fair value to its carrying value, using a discounted cash flow methodology. As a result, during the first quarter of 2002, SEI recorded a pre-tax charge of $6 million related to the impairment of goodwill associated with its two domestic subsidiaries. Impairment losses are reflected in Other Operating Expenses in the Statements of Consolidated Income.

If goodwill amortization had not been recorded in 2001, reported net income for 2001 would have increased by $15 million to $533 million. Basic and diluted earnings per share would have increased by $0.07 to $2.61 and $2.59 respectively.

During 2002, SET completed several acquisitions as further discussed in Note 2. As a result of SET's acquisition of the metals warehousing business, the company recorded $21 million of goodwill on the Consolidated Balance Sheets. In addition, a $16 million after-tax extraordinary gain reflecting negative goodwill was recorded in 2002 for the purchase of the base metals and concentrates businesses.

During the first quarter of 2003 SEI purchased the remaining minority interests in its Mexican subsidiaries, which resulted in the recording of an addition to goodwill of $6 million and to an intangible asset of $4 million.

The changes in the carrying amount of goodwill (included in Noncurrent Sundry Assets on the Consolidated Balance Sheets) for the years ended December 31, 2003 and 2002 are as follows:

(Dollars in millions)	SET	Other	Total
Balance as of January 1, 2002	$ 120	$ 52	$ 172
Goodwill acquired during the year	21	--	21
Impairment losses	--	(6)	(6)
Other	--	(5)	(5)
Balance as of December 31, 2002	141	41	182
Goodwill acquired during the year	--	6	6
Balance as of December 31, 2003	$ 141	$ 47	$ 188

SET is the only reportable segment that has goodwill. In addition, the unamortized goodwill related to unconsolidated subsidiaries (included in Investments on the Consolidated Balance Sheets), primarily those located in South America, was $299 million and $294 million at December 31, 2003 and 2002, respectively, before foreign currency translation adjustments. Including foreign currency translation adjustments, these amounts were $232 million and $219 million, respectively. Unamortized other intangible assets were not material at December 31, 2003 and 2002.

SFAS 143, "Accounting for Asset Retirement Obligations": SFAS 143, issued in July 2001, addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of long-lived assets, such as nuclear plants. It requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset by the present value of the future retirement cost. Over time, the liability is accreted to its full value and paid, and the capitalized cost is depreciated over the useful life of the related asset.

The adoption of SFAS 143 on January 1, 2003 resulted in the recording of an addition to utility plant of $71 million, representing the company's share of SONGS estimated future decommissioning costs (as discounted to the present value at the dates the units began operation), and accumulated depreciation of $41 million related to the increase to utility plant, for a net increase of $30 million. In addition, the company recorded a corresponding retirement obligation liability of $309 million (which includes accretion of that discounted value to December 31, 2002) and a regulatory liability of $215 million to reflect that SDG&E has collected the funds from its customers more quickly than SFAS 143 would accrete the retirement liability and depreciate the asset. These liabilities, less the $494 million recorded as accumulated depreciation prior to January 1, 2003 (which represents amounts collected for future decommissioning costs), comprise the offsetting $30 million. See further discussion of SONGS' decommissioning and the related nuclear decommissioning trusts in Note 6.

On January 1, 2003, the company recorded additional asset retirement obligations of $20 million associated with the future retirement of a former power plant and three storage facilities.

In accordance with SFAS 143, Sempra Energy identified several other assets for which retirement obligations exist, but whose lives are indeterminate. A liability for these asset retirement obligations will be recorded if and when a life is determinable.

The change in the asset retirement obligations for the year ended December 31, 2003 is as follows (dollars in millions):

Balance as of January 1, 2003	$ --
Adoption of SFAS 143	329
Accretion expense	22
Payments	(14)
Balance as of December 31, 2003	$ 337*

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

Had SFAS 143 been in effect on January 1, 2002, the asset retirement obligation liability would have been $363 million as of that date.

Except for the items noted above, the company has determined that there is no other material retirement obligation associated with tangible long-lived assets.

Implementation of SFAS 143 has had no effect on results of operations and is not expected to have a significant effect in the future.

In accordance with CPUC regulations, the California Utilities collect estimated removal costs in rates through depreciation. SFAS 143 also requires the company to reclassify estimated removal costs, which have historically been recorded in accumulated depreciation, to a regulatory liability. At December 31, 2003, these costs were $1.4 billion and $846 million for SoCalGas and SDG&E, respectively. At December 31, 2002, the corresponding amounts were $1.3 billion and $1.2 billion for SoCalGas and SDG&E, respectively. The decrease in the SDG&E amount during 2003 is due to SFAS 143 requiring further reclassification of those costs related to a legal obligation (primarily SONGS costs) to Asset Retirement Obligations.

SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets": In August 2001, the FASB issued SFAS 144, which replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." It applies to all long-lived assets. Among other things SFAS 144 requires that those long-lived assets classified as held for sale be measured at the lower of carrying amount (cost less accumulated depreciation) or fair value less cost to sell.

During the third and fourth quarters of 2003, the company recorded impairment charges of $77 million and $24 million to write down the carrying value of the assets of Frontier Energy and AEG, respectively. The Frontier Energy impairment resulted from reductions in actual and anticipated sales of natural gas by the utility. The AEG impairment was due to less than anticipated customer growth. These charges are included in Other Operating Expenses in the Statements of Consolidated Income. In applying the provisions of SFAS 144, management determined the fair value of such assets based on its estimates of discounted future cash flows.

SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure": In December 2002, the FASB issued SFAS 148, an amendment to SFAS 123, "Accounting for Stock-Based Compensation," which gives companies electing to expense employee stock options three methods to do so. In addition, the statement amends the disclosure requirements to require more prominent disclosure about the method of accounting for stock-based employee compensation and the effect of the method used on reported results in both annual and interim financial statements.

The company has elected to continue using the intrinsic value method of accounting for stock-based compensation. Therefore, SFAS 148 will not have any effect on the company's financial statements. See Note 9 for additional information regarding stock-based compensation.

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

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity": This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that certain mandatorily redeemable financial instruments previously classified in the mezzanine section of the balance sheet be reclassified as liabilities. The company adopted SFAS 150 beginning July 1, 2003 by reclassifying $200 million of mandatorily redeemable trust preferred securities to Deferred Credits and Other Liabilities and $24 million of mandatorily redeemable preferred stock of subsidiaries to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets. In addition, dividend payments required on these instruments, previously recorded to Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded to Interest Expense on the company's Statements of Consolidated Income. For the year ended December 31, 2003, the related amount recorded as interest expense for the last six months totaled $9 million. On December 31, 2003, the $200 million of mandatorily redeemable trust preferred securities were reclassified to Due to Unconsolidated Affiliates due to the adoption of FIN 46 as discussed below.

EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": In accordance with the EITF's rescission of Issue 98-10 by the release of Issue 02-3, the company no longer recognizes energy-related contracts under mark-to-market accounting unless the contracts meet the requirements stated under SFAS 133 and SFAS 149, which is the case for a substantial majority of the company's contracts. On January 1, 2003, the company recorded the initial effect of Issue 98-10's rescission as a cumulative effect of a change in accounting principle, which reduced after-tax earnings by $29 million.

On a net basis, $9 million of the $29 million was realized during the year ended December 31, 2003. Neither the cumulative nor the ongoing effect impacts the company's cash flow or liquidity.

EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities": In June 2002, a consensus was reached in EITF 02-3, which codifies and reconciles existing guidance on the recognition and reporting of gains and losses on energy trading contracts, and addresses other aspects of the accounting for contracts involved in energy trading and risk management activities. Among other things, the consensus requires that mark-to-market gains and losses on energy trading contracts should be shown on a net basis in the income statement, effective for financial statements issued for periods ending after July 15, 2002. Adoption of EITF 02-3 in 2002 required that SES change its method of recording trading activities from gross to net, which had no impact on previously recorded gross margin, net income or cash provided by operating activities. SET was already recording revenues from trading activities on a net basis and required no change.

For 2001, recording revenues for all trading activities on a net basis decreased previously reported revenues by $348 million to $7.7 billion. There was no impact on reported revenues for the years ending December 31, 2003 and 2002 as trading activities were already reported on a net basis.

EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities and Not 'Held for Trading Purposes' as Defined in EITF 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": During 2003, the EITF reached a consensus that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Adoption of EITF 03-11 in 2003 did not have a significant impact to the company's financial statements and the company does not expect a significant impact in the future.

FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees": In November 2002, the FASB issued FIN 45, which elaborates on the disclosures to be made in interim and annual financial statements of a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing a guarantee. As of December 31, 2003, substantially all of the company's guarantees were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries. The only significant guarantees for which disclosure is required are that of the synthetic lease for the Mesquite Power plant, the mandatorily redeemable trust preferred securities and $25 million related to debt issued by Chilquinta Energia Finance, LLC, an unconsolidated affiliate. The synthetic lease for the Mesquite Power plant and the mandatorily redeemable trust preferred securities were also affected by FIN 46, as described below.

FIN 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51": FIN 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the entity. During December 2003, the FASB issued FIN 46 revised (FIN 46R) to defer the implementation date for pre-existing variable interest entities (VIEs) that are special purpose entities (SPEs) until the end of the first interim or annual period ending after December 15, 2003. For VIEs that are not SPEs, companies must apply FIN 46R no later than the end of the first reporting period ending after March 15, 2004.

Sempra Energy has identified two VIEs for which it is the primary beneficiary. One of the VIEs (Mesquite Trust), which is an SPE, is the owner of the Mesquite Power plant for which the company had a synthetic lease agreement, as described in Notes 2 and 5. The Mesquite Power plant is a 1,250-megawatt (MW) project that provides electricity to wholesale energy markets in the Southwest. Construction began in September 2001 and the first phase of commercial operations (50 percent of the plant's total capacity) began in June 2003. The second phase of commercial operations (the remaining 50 percent) began in December 2003. Accordingly, as the FASB's deliberations during the deferral period did not result in the exclusion of Mesquite Trust from FIN 46's definitions, Sempra Energy consolidated this entity in its financial statements at December 31, 2003. The company bought out the lease in January 2004. At December 31, 2003, the total assets and total liabilities of Mesquite Trust were $643 million and $630 million, respectively. The company also recorded an after-tax credit for the cumulative effect from the change in accounting principle of $9 million.

The other variable interest entity is AEG, which markets power and natural gas commodities to commercial and residential customers in the United Kingdom. Sempra Energy consolidated AEG in its financial statements at December 31, 2003. Consolidation of AEG required Sempra Energy to record 100 percent of AEG's December 31, 2003 balance sheet, whereas it previously recorded only its share of AEG's net operating results. As of December 31, 2003 total assets and total liabilities of this unconsolidated subsidiary were $180 million and $251 million, respectively. Due to AEG's consolidation, the company recorded an after-tax charge for the cumulative effect of the change in accounting principle of $26 million.

In accordance with FIN 46R, the company deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. The trust has no assets except for its corresponding receivable from the company. Due to the deconsolidation of this entity, Sempra Energy has reclassified $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates on its Consolidated Balance Sheets.

FASB Staff Position (FSP) 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003": Issued January 12, 2004, FSP 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The company has elected to defer the effects of the Act as provided by FSP 106-1. Any measure of the accumulated postretirement benefit obligation or net periodic postretirement benefit cost in the financial statements or the accompanying notes do not reflect the impact of the Act on the plans. At this time, specific authoritative guidance on the accounting for the federal subsidy provided by the Act is pending and that guidance could require the company to change previously reported information.

Other Accounting Standards: During 2003 and 2002 the FASB and the EITF issued several statements that are not applicable to the company but could be in the future. In April 2002, the FASB issued SFAS 145, which rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt," and SFAS 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements." In June 2002, the FASB issued SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS 146 supersedes previous accounting guidance, principally EITF 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)."

NOTE 2. RECENT ACQUISITIONS AND INVESTMENTS

Sempra Energy Trading

In 2003, SET spent $27 million related to the development of Bluewater Gas Storage, LLC, a natural gas storage facility in Michigan. SET owns the rights to develop the facility and to utilize its capacity to store natural gas for customers who buy, sell or transport natural gas in Michigan. The facility is expected to commence operations in 2004.

During 2002, SET completed $119 million of acquisitions that added base metals trading and warehousing to its trading business. On February 4, 2002, SET completed the acquisition of London-based Sempra Metals Limited, a leading metals trader on the London Metals Exchange, for $65 million, net of cash acquired. In April 2002 SET completed the acquisition of the assets of New York-based Sempra Metals & Concentrates Corp., a leading global trader of copper, lead and zinc concentrates, for $24 million. Also in April 2002, SET completed the acquisition of Henry Bath & Sons Limited, which provides warehousing services for non-ferrous metals in Europe and Asia, and the assets of the U.S. warehousing business of Henry Bath, Inc., for a total of $30 million, net of cash acquired.

As discussed in Note 1, the company recognized an extraordinary after-tax gain of $16 million for negative goodwill for the acquisitions of the base metals and concentrates businesses. Additional information on the extraordinary gain is provided in Note 1. In addition, goodwill of $21 million related to the acquisition of the metals warehousing business was recorded on the Consolidated Balance Sheets and is expected to be fully deductible for tax purposes.

Sempra Energy Resources

In October 2002 SER purchased a 305-MW, coal-fired power plant (renamed Twin Oaks Power) for $120 million. SER sells substantially all of the output of the plant under a five-year contract expiring on October 1, 2007. In connection with the acquisition, SER also assumed a contract that includes annual commitments to purchase coal for the plant until an aggregate minimum volume has been achieved or through 2025.

Termoelectrica De Mexicali (TDM), a 600-MW power plant near Mexicali, Baja California, Mexico, commenced operations in July 2003. In May 2003, a federal judge issued an order finding that the U.S. Department of Energy's (DOE) abbreviated assessment of two Mexicali power plants, including SER's TDM plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. On July 8, 2003, the judge ordered the DOE to conduct additional environmental studies, but denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE has until May 15, 2004, to demonstrate why the court should not set aside the permits. Through December 31, 2003, TDM has made capital expenditures of $342 million.

The 1,250-MW Mesquite Power plant, located near Phoenix, Arizona, cost $686 million and provides electricity to wholesale energy markets in the Southwest. The first phase of commercial operations (50 percent of the plant's total capacity) began in June 2003. The second phase of commercial operations (the remaining 50 percent) began in December 2003. As of December 31, 2003, this project was owned by the Mesquite Trust and financed through a synthetic lease agreement. Through December 31, 2003, SER had borrowed $630 million under this facility. All amounts above $280 million required collateralization through purchases of U.S. Treasury obligations. The collateralized U.S. Treasury obligation amounted to $363 million at December 31, 2003. This is included in Short-Term Investments on the Consolidated Balance Sheets. As a result of implementing FIN 46, Sempra Energy consolidated the Mesquite Trust, which had total assets and total liabilities of $643 million and $630 million, respectively, at December 31, 2003. See further discussion under "New Accounting Standards" in Note 1. On January 21, 2004, SER elected to purchase all of the power plant assets of Mesquite Trust for $631 million. The purchase required cash of $268 million and the liquidation of the $363 million in treasury securities held by the Mesquite Trust as collateral.

Sempra Energy LNG Corp.

In April 2003, Sempra Energy LNG Corp. (SELNG) completed its acquisition of the proposed Cameron liquefied natural gas (LNG) project in Hackberry, Louisiana from a subsidiary of Dynegy, Inc. SELNG has paid Dynegy $36 million for the acquisition, which includes rights to the location, licensing and FERC approval of the project, which is still in the permitting stage. Additional payments are contingent on meeting certain benchmarks and milestones and the performance of the project. As of December 31, 2003, the company had accrued $30 million as an estimate of the contingent payment. The total cost of the project is expected to be $700 million. The terminal will be capable of supplying 1.5 billion cubic feet (bcf) of natural gas per day. Construction is expected to begin in 2004 and commercial operations could begin in 2007. FERC approved the construction and operation of the project in September 2003.

In December 2003, SELNG and Shell International Gas Limited (Shell) announced plans to form a 50/50 joint venture to build, own and operate Energia Costa Azul, a LNG receiving terminal in Baja California on the west coast of Mexico, approximately 50 miles south of San Diego. The proposed joint venture will combine the two separate Baja California LNG receiving terminals proposed by Shell and SELNG into a single project. It is expected that construction will begin in 2004 with terminal operations commencing in 2007. The cost of the project is estimated to be $600 million. The terminal will be capable of supplying 1 billion cubic feet (bcf) of natural gas per day, half of which will be used to meet the growing energy demands in western Mexico. The proposed joint venture contemplates that SELNG and Shell would share the investment costs of the terminal equally and each would take 50 percent of the capacity of the terminal. Any surplus natural gas from the facility will be used to provide new natural gas supplies for the southwestern United States.

Also in December 2003, SELNG, British Petroleum and BPMiGas signed a non-binding Heads of Agreement (HOA) for the supply of 500 million cubic feet of gas a day from Indonesia's Tangguh LNG liquefaction facility to Energia Costa Azul. The non-binding HOA is expected to be the precursor to a full 20-year purchase/supply agreement.

Also in connection with this project, Mexico's national environmental agency issued an environmental permit in April 2003. Three other significant permits, an operating permit from Mexico's energy regulatory commission, a local land-use permit from the City of Ensenada and a coastal zone use permit, were granted in 2003. The permit to construct marine facilities is pending and expected to be received in the near future. In November 2003, a Mexican tribunal issued the equivalent of a preliminary injunction against a Mexican environmental agency's adoption of the environmental impact authorization covering the project. The injunction temporarily suspends the permit until the matter can proceed to a hearing on the merits of the authorization. Sempra Energy believes the suspension of these permits will be temporary and will not delay the 2007 commercial start date of the terminal.

Sempra Energy International

SEI's Mexican subsidiaries build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. On February 7, 2003, SEI purchased the remaining minority interests in its Mexican subsidiaries.

NOTE 3. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Investments are accounted for under the equity method when the company has an ownership interest of twenty to fifty percent. In these cases the company's pro rata shares of the subsidiaries' net assets are included in Investments on the Consolidated Balance Sheets, and are adjusted for the company's share of each investee's earnings or losses, dividends and foreign currency translation effects. Earnings are recorded as equity earnings in Other Income - Net on the Statements of Consolidated Income.

The company accounts for certain investments in housing partnerships made before May 19, 1995 under the cost method, whereby they are amortized over ten years based on the expected residual value. The company has no unconsolidated subsidiaries where its ability to influence or control an investee differs from its ownership percentage.

The company's long-term investments are summarized as follows:

(Dollars in millions)	December 31, 2003	December 31, 2002
Equity method investments:		
Chilquinta Energia	$ 337	$ 387
Luz del Sur	177	117
Sodigas Pampeana and Sodigas Sur	66	17
Elk Hills power project	218	172
El Dorado Energy	68	73
Sempra Energy Financial housing partnerships	175	206
Sempra Energy Financial synthetic fuel partnerships	14	8
Total	1,055	980
Cost method investments:		
Sempra Energy Financial housing partnerships	47	57
Other	12	3
Total	59	60
Investments in unconsolidated subsidiaries	1,114	1,040
Other:		
Mesquite power plant project		
Collateralized U.S. Treasury obligations*	--	228
Reimbursable project costs	--	45
Total	--	273
Total long-term investments	$ 1,114	$ 1,313

* The balance of $363 million at December 31, 2003 was reclassified to Short-Term Investments.

For equity method investments, costs in excess of equity in net assets were $232 million and $219 million at December 31, 2003 and 2002, respectively. Through December 31, 2001, the excess of the investment over the related equity in net assets had been amortized over various periods, primarily forty years (see Note 1). In accordance with SFAS 142, amortization ceased in 2002. Costs in excess of the underlying equity in net assets will continue to be reviewed for impairment in accordance with APB Opinion 18, "The Equity Method of Accounting for Investments in Common Equity." See additional discussion of SFAS 142 in "New Accounting Standards" in Note 1. Descriptive information concerning each of these subsidiaries follows.

Sempra Energy International

SEI and PSEG Global (PSEG), an unaffiliated company, each own a 50-percent interest in Chilquinta Energia S.A., a Chilean electric utility, and 44 percent interests in Luz del Sur S.A.A. (Luz del Sur), a Peruvian electric utility.

SEI also owns 43 percent of two Argentine natural gas utility holding companies, Sodigas Pampeana S.A. and Sodigas Sur S.A. As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent declines in the value of the peso, SEI had reduced the carrying value of its investment downward by a cumulative total of $197 million as of December 31, 2003. These non-cash adjustments continue to occur based on fluctuations in the Argentine peso. They do not affect net income, but increase or decrease other comprehensive income (loss) and accumulated other comprehensive income (loss).

The related Argentine economic decline and government responses (including Argentina's unilateral, retroactive abrogation of utility agreements early in 2002) continue to adversely affect the operations of these Argentine utilities. In 2002, SEI initiated arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its investments that has resulted from Argentine governmental actions. In 2003, SEI filed its legal brief with the International Center for Settlement of Investment Disputes, outlining its claims for $258 million. The company has also presented additional information that may provide a basis for a larger award. A decision is expected in early 2005. Sempra Energy also has a $48.5 million political-risk insurance policy under which it filed a claim to recover a portion of the investments' diminution in value.

Sempra Energy Resources

The 550-MW Elk Hills Power (Elk Hills) project, which is located near Bakersfield, California, began commercial operations in July 2003. Elk Hills is 50 percent owned by SER in a joint venture with Occidental Energy Ventures Corporation.

The 480-MW El Dorado power plant, located near Las Vegas, Nevada, began commercial operations in May 2000. The El Dorado Energy project is 50 percent owned by SER in a joint venture partnership with Reliant Energy Power Generation.

At December 31, 2003, the investments in U.S. Treasury obligations related to the Mesquite project was reclassified to short-term investments as the result of the company buying out the lease in January 2004. See discussion in Note 1.

Sempra Energy Financial (SEF)

SEF invests as a limited partner in affordable-housing properties. SEF's portfolio includes 1,300 properties throughout the United States that are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also has an investment in a limited partnership which produces synthetic fuel from coal. Whether SEF will invest in additional properties will depend on Sempra Energy's income tax position. See additional discussion of income tax issues in Note 7.

NOTE 4. SHORT-TERM BORROWINGS

At December 31, 2003, the company had available $2.1 billion in unused, committed lines of credit to provide liquidity and support commercial paper.

Committed Lines of Credit

Sempra Energy Global Enterprises (Global) has two syndicated revolving credit agreements, each permitting revolving credit borrowings of $500 million. One is a 364-day credit agreement that may be converted into a one-year term loan upon the August 2004 expiration of the revolving credit period. The other is a three-year agreement permitting revolving credit borrowings until the expiration of the agreement in August 2006. Borrowings under the agreements are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit ratings. Both agreements require Sempra Energy to maintain a debt-to-total capitalization ratio (as identically defined in each agreement) of not to exceed 65 percent. Global had no commercial paper outstanding at December 31, 2003 and $422 million of commercial paper outstanding at December 31, 2002. As of December 31, 2003, a letter of credit for $18 million was outstanding under the second agreement.

SER has a syndicated $400 million revolving credit agreement guaranteed by Sempra Energy. The agreement requires Sempra Energy to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent. The agreement expires in August 2004 and borrowings bear interest at rates varying with market rates and Sempra Energy's credit rating. At December 31, 2003, SER had no outstanding borrowings under the agreement. At December 31, 2002, there was $100 million outstanding under the agreement. See Note 5 for additional information on SER's borrowings.

The California Utilities have a combined revolving line of credit, under which each utility individually may borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement bear interest at rates varying with market rates and the utility's credit rating. The revolving credit commitment expires in May 2004, at which time outstanding borrowings may be converted into a one-year term loan subject to any requisite regulatory approvals related to long-term debt. The agreement requires each utility to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 60 percent. Borrowings under the agreement are individual obligations of the borrowing utility and a default by one utility would not constitute a default or preclude borrowings by the other. These lines of credit have never been drawn upon. At December 31, 2003 and 2002, the California Utilities had no commercial paper outstanding.

PE has a $375 million revolving agreement, guaranteed by Sempra Energy, for the purpose of providing loans to Global. The revolving credit commitment, initially $500 million, and $375 million at December 31, 2003, declines semi-annually by $125 million until expiration on April 5, 2005. Borrowings are guaranteed by Sempra and are subject to mandatory repayment prior to the maturity date should SoCalGas' unsecured long-term credit ratings cease to be at least BBB by Standard & Poor's (S&P) and Baa2 by Moody's Investor Services, Inc. (Moody's), should Sempra Energy's or SoCalGas' debt-to-total capitalization ratio (as defined in the agreement) exceed 65 percent, or should there be a change in law materially and adversely affecting the ability of SoCalGas to pay dividends or make distributions to PE. Borrowings bear interest at rates varying with market rates, PE's credit ratings and the amount of outstanding borrowings. This line of credit has never been used.

Uncommitted Lines of Credit

SET has $770 million in various uncommitted lines of credit that are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit rating. At December 31, 2003, SET had $420 million of letters of credit, but no short-term borrowings, outstanding against these lines. The corresponding amounts outstanding at December 31, 2002 were $345 million and $115 million, respectively.

Other

Sempra Energy Solutions had $28 million of short-term debt with an average interest rate of 7.56% outstanding at December 31, 2003 and $33 million at December 31, 2002. Sempra Energy had no other short-term debt at December 31, 2003. The company's weighted average interest rate for short-term borrowings outstanding at December 31, 2002 was 2.02%

NOTE 5. LONG-TERM DEBT

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December 31,
(Dollars in
millions)
2003 2002 -

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~~First mortgage bonds 4.375% January 15, 2011 $ 100 $ -- Variable rates after fixed to floating rate swaps (1.43% at December 31, 2003) January 15, 2011 150 -- 4.8% October 1, 2012 250 250 6.8% June 1, 2015 14 14 5.45% April 15, 2018 250 -- 5.9% June 1, 2018 68 68 5.9% to 6.4% September 1, 2018 176 176 6.1% September 1, 2019 35 35 Variable rates (1.25% at December 31, 2003) September 1, 2020 58 58 5.85% June 1, 2021 60 60 6.875% November 1, 2025 175 175 5.25% to 7% December 1, 2027 225 225 5.75% November 15, 2003 -- 100 7.375% March 1, 2023 -- 100 7.5% June 15, 2023 -- 125~~

~~Total 1,561 1,386 Other long-term debt Variable rates due September 2005 (2.02% to 5.12% at December 31, 2003) 630 -- 5.60% equity units May 17, 2007 600 600 Notes payable at variable rates after a fixed to~~

~~floating rate swap (2.49% at December 31, 2003) July 1, 2004 500 500 7.95% Notes March 1, 2010 500 500 6.0% Notes due February 1, 2013 400 — 6.95% Notes December 1, 2005 300 300 Rate-reduction bonds, 6.31% to 6.37% annually through 2007 263 329 5.9% June 1, 2014 130 130 Debt incurred to acquire limited partnerships, secured by real estate, at 7.13% to 9.35% annually through 2009 110 145 Employee Stock Ownership Plan Bonds at 7.375% November 1, 2014 82 82 Bonds at variable rates (1.65% at December 31, 2003) November 1, 2014 19 19 Variable rates (1.45% at December 31, 2003) December 1, 2021 60 60 Variable rates (1.46% at December 31, 2003) July 1, 2021 39 39 6.75% March 1, 2023 25 25 6.375% May 14, 2006 8 8 5.67% January 18, 2028 5 75 Other variable-rate debt 15 18 Capitalized leases 8 10 SER line of credit at variable rates August 21, 2004 — 100 Market value adjustments for interest rate swaps — net (expires July 1, 2004) 23 42 ------------ ----------- 5,278 4,368 Current portion of long-term~~

~~debt (1,433) (281) Unamortized discount on long term debt (4) (4)~~

~~Total $3,841 $4,083~~

Excluding capital leases, which are described in Note 15, and market value adjustments for interest-rate swaps, maturities of long-term debt are $1.4 billion in 2004, $397 million in 2005, $101 million in 2006, $682 million in 2007, $8 million in 2008 and $2.7 billion thereafter.

On January 26, 2004, SoCalGas optionally redeemed its $175 million 6.875% first mortgage bonds. Therefore that liability is classified as current at December 31, 2003. On January 21, 2004, SER elected to purchase the assets of Mesquite Trust and extinguish the $630 million of related debt outstanding. Therefore that liability also is classified as short-term at December 31, 2003. Holders of variable-rate bonds may require the issuer to repurchase them prior to scheduled maturity. However, since repurchased bonds would be remarketed and funds for repurchase are provided by revolving credit agreements (which are generally renewed upon expiration and which are described in Note 4), it is expected that the bonds will be held to the maturities stated above. Interest rates on the $500 million of notes maturing in 2004 can vary with the company's credit ratings.

Issuances of $900 million, $1.2 billion and $675 million of long-term debt, and payments of $601 million, $479 million and $681 million on long-term debt were made in 2003, 2002 and 2001, respectively.

Callable Bonds

At the company's option, certain bonds are callable at various dates. Of the company's callable bonds, $873 million are callable in 2004, $105 million in 2005, $8 million in 2006 and $45 million thereafter.

First Mortgage Bonds

The first mortgage bonds were issued by the California Utilities and are secured by a lien on their respective utility plant. The California Utilities may issue additional first mortgage bonds upon compliance with the provisions of their bond indentures, which require, 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 $2.8 billion of first mortgage bonds at December 31, 2003.

During the first quarter of 2001, SDG&E remarketed $150 million of variable-rate first mortgage bonds for various terms at a fixed rate of 7%. $45 million of these bonds came to term on December 1, 2003 and were remarketed to maturity with a rate of 5.25%. At SDG&E's option, the remaining bonds may be remarketed at a fixed or floating rate at December 1, 2005, the expiration of the fixed terms.

In November 2001, SoCalGas optionally redeemed its $150 million 8.75% first mortgage bonds. In December 2001, SoCalGas entered into an interest-rate swap which effectively exchanged the fixed rate on its $175 million 6.875% first mortgage bonds for a floating rate. In September 2002, SoCalGas terminated the swap, receiving cash proceeds of $10 million, comprised of $4 million in accrued interest and a $6 million amortizable gain.

In June 2002, SDG&E paid at maturity its $28 million 7.625% first mortgage bonds. In July 2002 the company optionally redeemed its $10 million 8.5% first mortgage bonds.

In August 2002, SoCalGas paid at maturity its $100 million 6.875% first mortgage bonds. In October 2002, SoCalGas publicly offered and sold $250 million of 4.8% first mortgage bonds, maturing on October 1, 2012. The bonds are not subject to a sinking fund and are redeemable prior to maturity only through a make-whole mechanism. Proceeds from the bond sale were used to replenish amounts previously expended to refund and retire indebtedness, and for working capital and other general corporate purposes.

On April 7, 2003, SoCalGas optionally redeemed its $100 million 7.375% first mortgage bonds. On August 21, 2003, SoCalGas optionally redeemed its $125 million 7.5% first mortgage bonds.

On October 17, 2003, SoCalGas issued $250 million of 5.45% first mortgage bonds due in April 2018. The proceeds were used to replenish amounts previously expended to refund and retire indebtedness and for general corporate purposes. On November 17, 2003, SoCalGas paid off its $100 million 5.75% first mortgage bonds.

On December 15, 2003, SoCalGas issued $250 million of 4.375% first mortgage bonds maturing in January 2011. The proceeds were used to retire outstanding debt and for other general corporate purposes. On December 15, 2003, SoCalGas entered into an interest-rate swap which effectively exchanged the fixed rate on $150 million of the 4.375% first mortgage bonds for a floating rate.

Mesquite Power

The company consolidated Mesquite Trust, the owner of Mesquite Power, on its financial statements as of December 31, 2003 as a result of implementing FIN 46. The debt outstanding was $630 million comprised of notes payable due in 2005 at various interest rates. On January 21, 2004, SER elected to purchase all of the power plant assets of Mesquite Trust for $631 million and extinguished the related Mesquite debt. Therefore the liability is classified as short-term at December 31, 2003. See further discussion under New Accounting Standards in Note 1. For additional information on the Mesquite Power synthetic lease, refer to Note 2.

Equity Units

In April and May of 2002, the company publicly offered and issued $600 million of Equity Units. For additional information on Equity Units refer to Note 12.

Unsecured Long-term Debt

Various long-term obligations totaling $2.7 billion are unsecured at December 31, 2003.

In February 2001, SDG&E remarketed $25 million of variable-rate unsecured bonds as 6.75 percent fixed-rate debt for a three-year term.

In June 2001, the company issued $500 million of 6.8% notes due July 1, 2004. Sempra Energy has a fixed-to-floating rate swap on these notes. In October 2001, SoCalGas paid at maturity its $120 million of 6.38% medium-term notes.

SER borrowed $100 million on its $400 million line of credit in October 2002 and repaid it in March 2003. There were no loans outstanding on SER's line of credit at December 31, 2003. This agreement expires in August 2004 and bears interest at rates varying with market rates and Sempra Energy's credit ratings. For additional information regarding this line of credit see Note 4.

On January 15, 2003, $70 million of SoCalGas' 5.67% $75 million medium-term notes were put back to the company. The remaining $5 million matures in 2028.

In January 2003, the company issued $400 million of long-term 6% notes due in February 2013. The bonds are not subject to a sinking fund and are redeemable prior to maturity only through a make-whole mechanism. The proceeds were used to pay down commercial paper.

Rate-Reduction Bonds

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

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

The Trust covers substantially all of the employees of the parent organization, SoCalGas and most of Global's subsidiaries. The Trust is used to fund part of the retirement savings plan described in Note 8. The 15-year notes are repriced weekly and subject to repurchase by the company at the holder's option, depending on market demand. In June 2001, utilizing the term option provisions of the notes, $82 million of the notes were remarketed at a fixed rate of 7.375 percent for three years. The variable interest rate and weekly repricing resume in May 2004. ESOP debt was reduced by $4.2 million during the last three years when 70,000 shares of company common stock were released from the Trust in order to fund the employer contribution to the company savings plan. Interest on the ESOP debt amounted to $6 million in 2003, $7 million in 2002 and $6 million in 2001. Dividends used for debt service amounted to $2 million in 2003, $3 million in 2002, and $3 million in 2001.

Interest-Rate Swaps

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. The schedule of long-term debt reflects past swap interest rates. The company believes the swaps have been fully effective in their purpose of converting the underlying debt's fixed rates to floating rates and meet the criteria for accounting under one of the methods defined in SFAS 133 for fair value hedges of debt instruments. Accordingly, market value adjustments to long-term debt of ($19) million and $20 million were recorded in 2003 and 2002, respectively, to reflect, without affecting net income or other comprehensive income, the favorable or (unfavorable) economic consequences (as measured at December 31, 2003 and 2002) of having entered into the swap transactions.

During 2002 and 2001, SDG&E had an interest-rate swap agreement that effectively fixed the interest rate on $45 million of variable-rate underlying debt at 5.4 percent. This floating-to-fixed-rate swap did not qualify for hedge accounting and, therefore, the gains and losses associated with the change in fair value are recorded in the Statements of Consolidated Income. The effect on net income was a $1 million gain in 2002 and a $1 million loss in 2001.

Foreign Currency Hedges

The company's primary objective with respect to currency risk is to reduce net income volatility that would otherwise occur due to exchange-rate fluctuations.

Sempra Energy's net investment in its Latin American operating companies and the resulting cash flows are partially protected against normal exchange-rate fluctuations by rate-setting mechanisms that are intended to compensate for local inflation and currency exchange-rate fluctuations. In addition to establishing such tariff-based protections, the company offsets material cross-currency transactions and net income exposure through various means, including financial instruments and short-term investments.

Because the company does not hedge its net investment in foreign countries, it is susceptible to volatility in other comprehensive income, as occurred in the last three years primarily as a result of decoupling the Argentine peso from the U.S. dollar, as discussed in Note 3.

NOTE 6. FACILITIES UNDER JOINT OWNERSHIP

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2003, are as follows:

(Dollars in millions) Project	SONGS	Southwest Powerlink
Percentage ownership (1)	20%	89%
Utility plant in service	$ 11	$237
Accumulated depreciation and amortization	$ 5	$141
Construction work in progress	$ --	$ 27

(1) SDG&E's 20% ownership in SONGS has been fully recovered and is no longer included under utility plant and accumulated depreciation.

The amounts specified above for SONGS represent wholly owned substation equipment. As of December 31, 2003, the company has fully recovered its interest in SONGS through the ICIP mechanism. Additional information concerning the ICIP mechanism is provided in Note 13.

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

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

SONGS Decommissioning

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

The company's share of decommissioning costs for the SONGS units is estimated to be $316 million in 2003 dollars. Cost studies are updated every three years, with the next update expected to be submitted to the CPUC for its approval in 2005. Rate recovery of decommissioning costs is allowed until the time that the costs are fully recovered, and is subject to adjustment every three years based on the costs allowed by regulators. Collections are authorized to continue until 2013, but may be extended by CPUC approval until 2022, at which time the SONGS' operating license ends and the decommissioning of SONGS 2 and 3 would be expected to begin. Payments to the nuclear decommissioning trusts (described in "Nuclear Decommissioning Trusts") are expected to continue until 2013 at which time sufficient funds are expected to be collected to fully decommission SONGS. If funds are not sufficient, additional future rate recovery is expected to occur.

The amounts collected in rates are invested in the externally managed trust funds. The securities held by the nuclear decommissioning trusts are considered available for sale. These trusts are shown on the Consolidated Balance Sheets at market value. At December 31, 2003, these trusts reflected unrealized gains of $159 million with the offsetting credits recorded on the Consolidated Balance Sheets to Asset Retirement Obligations and the related regulatory liabilities. At December 31, 2002, these trusts reflected unrealized gains of $95 million with the offsetting credits recorded to Deferred Credits and Other Liabilities and the related regulatory liabilities.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled, removed and disposed of. Preparations have been made for the remaining major work to be performed in 2004 and beyond. That work will include dismantling, removal and disposal of all remaining Unit 1 equipment and facilities (both nuclear and non-nuclear components), decontamination of the site and completion of an on-site storage facility for Unit 1 spent fuel. These activities are expected to be completed in 2008.

See discussion regarding the impact of SFAS 143 in Note 1.

Nuclear Decommissioning Trusts

SDG&E has established a Nonqualified Nuclear Decommissioning Trust and a Qualified Nuclear Decommissioning Trust to provide funds for the decommissioning of SONGS as described above. Amounts held by these trusts are invested in accordance with CPUC regulations that establish maximum amounts for investments in equity securities (50 percent of the qualified trust and 60 percent of the nonqualified trust), international equity securities (20 percent) and securities of electric utilities having ownership interests in nuclear power plants (10 percent). Not less than 50 percent of the equity portion of these trusts must be invested passively.

At December 31, 2003 and 2002, trust assets were allocated as follows (dollars in millions):

	Qualified Trust		Nonqualified Trust	
	2003	2002	2003	2002
Domestic equity	$ 163	$ 143	$ 43	$ 36
Foreign equity	88	69	--	--
Total equity	251	212	43	36
Total fixed income	249	220	27	26
Total	$ 500	$ 432	$ 70	$ 62

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

Additional information regarding SONGS is included in Notes 13 and 15.

NOTE 7. INCOME TAXES

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

	Years ended December 31, 2003	2002	2001
Statutory federal income tax rate	35.0%	35.0%	35.0%
Utility depreciation	6.7	5.2	5.9
State income taxes - net of federal income tax benefit	7.0	7.0	6.4
Tax credits	(22.6)	(18.5)	(13.7)
Income from unconsolidated foreign subsidiaries	(4.3)	(2.0)	(3.0)
Settlement of Internal Revenue Service audit	(11.2)	(3.6)	--
Other - net	(4.3)	(2.9)	(1.5)
Effective income tax rate	6.3%	20.2%	29.1%

The components of total income (loss) from operations (including continuing extraordinary items) before income taxes are as follows:

(Dollars in millions)	2003	2002	2001
Domestic	$ 551	$ 584	$ 651
Foreign	191	137	80
Total income before income taxes	$ 742	$ 721	$ 731

The components of income tax expense are as follows:

(Dollars in millions)	2003	2002	2001
Current:			
Federal	$ 93	$ 195	$ 36
State	16	30	60
Foreign	11	13	11
Total	120	238	107
Deferred:			
Federal	(138)	(113)	104
State	53	31	1
Foreign	18	(5)	7
Total	(67)	(87)	112
Deferred investment tax credits	(6)	(5)	(6)
Total income tax expense	$ 47	$ 146	$ 213

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

(Dollars in millions)	2003	2002
Deferred tax liabilities:		
Differences in financial and tax bases of property, plant and equipment	$1,094	$ 883
Balancing accounts and regulatory assets	314	298
Partnership income	34	45
Unrealized revenue	63	53
Other	211	266
Total deferred tax liabilities	1,716	1,545
Deferred tax assets:		
Investment tax credits	61	62
General business tax credit carryforward	192	148
Net operating losses of foreign entities	112	89
Postretirement benefits	31	32
Other deferred liabilities	190	157
Restructuring costs	--	40
Compensation-related items	134	154
Bad debt allowance	28	--
State income taxes	57	46
Credits from Alternative Minimum Tax	74	19
Valuation allowance	(20)	(10)
Other	100	28
Total deferred tax assets	959	765
Net deferred income tax liability	$ 757	$ 780

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

(Dollars in millions)	2003	2002
Current (asset) liability	$ 123	$ (20)
Noncurrent liability	634	800
Total	$ 757	$ 780

In connection with its affordable-housing investments, the company has $192 million of unused general business tax credits in varying amounts dating back to 1999. The ability to offset these credits against future taxable income will expire between the years 2019 and 2022. The company expects to utilize the credits in future years. In addition, the company has $74 million of alternative minimum tax credits with no expiration date. All of these credits have been included in the company's calculation of income tax expense.

Foreign subsidiaries have $340 million in unused net operating losses available to reduce future income taxes, primarily in Mexico, Canada and the United Kingdom. Utilization of these losses began to expire in 2002. Financial statement benefits have been recorded on all but $66 million of these losses, primarily by offsetting them against deferred tax liabilities with the same expiration pattern and country of jurisdiction. No benefits have been recorded on $66 million of the losses because they have been incurred in jurisdictions where utilization is sufficiently in doubt.

The company has not provided for U.S. income taxes on foreign subsidiaries' undistributed earnings ($360 million at December 31, 2003), since they are expected to be reinvested indefinitely outside the U.S. It is not possible to predict the amount of U.S. income taxes that might be payable if these earnings were eventually repatriated.

Section 29 Income Tax Credits

In 2003 the Internal Revenue Service (IRS) issued Announcement 2003-46, stating it has reason to question the scientific validity of testing procedures and results related to Section 29 income tax credits. The notice also announced that it would suspend the issuance of new rulings until its review is complete and that rulings could be revoked if the IRS did not determine that the test procedures demonstrate a significant chemical change between the feedstock coal and the synthetic fuel. The IRS completed its review and on October 29, 2003, announced that it would again be issuing private letter rulings based on the previous requirements. Many such rulings have been issued since that date, including one involving operations owned by the company. The Permanent Subcommittee on Investigations of the U.S. Senate's Committee on Governmental Affairs has initiated an investigation on the subject of these income tax credits. In January 2004, the company received a letter from the Committee requesting certain information about its synthetic fuel operations and it is in the process of responding to this inquiry.

As part of its recently commenced normal audit program for the company for the period 1998-2001, the IRS notified the company of its intention to audit the synthetic fuel operations of SET and SEF. From acquisition of the facilities in 1998 through December 31, 2003, the company has recorded Section 29 income tax credits of $251 million of which $107 million were recorded for the year ended December 31, 2003. The company believes disallowance of Section 29 income tax credits is unlikely.

Luz del Sur

The Peruvian tax authorities (Sunat) had assessed additional taxes for 1999 based on their challenge of Luz del Sur's revaluation of its assets and also previously announced that they would assess additional taxes for the years 1996 through 1998 for the same concept. The Peruvian Tax Court recently ruled that no additional taxes could be assessed for 1996 through 1998 and that any additional taxes for 1999 could only be assessed if the Sunat showed that Luz del Sur had revalued its assets beyond their market value. If Sunat is successful in its challenge, income tax deductions for depreciation will be reduced, resulting in additional income taxes, interest and penalties aggregating as much as $10 million for the company's share for the period being questioned (1999) and $12 million for subsequent periods. The company believes that it has substantial defenses to such challenges and that the imposition of any additional taxes is not probable.

Spanish Holding Company

The IRS has issued Notice 2003-50, stating that regulations will be issued that will adversely affect foreign tax credit utilization by companies with "stapled-stock" affiliates. The company's intermediate parent company for many of its non-domestic subsidiaries is such a company. Although not probable, the most adverse resolution of this issue could result in a charge to net income of $13 million by the company.

Resolution of Certain Internal Revenue Service Matters

The company favorably resolved matters related to various prior years' returns during 2003. The primary issue involving the treatment of utility balancing accounts for the California Utilities was resolved following the issuance of an IRS Revenue Ruling and resolution of factual issues involving these claims with the IRS. The total effect on after-tax earnings and future cash flows for all IRS issues was $118 million, of which $79 million was at SDG&E and $29 million was at SoCalGas.

NOTE 8. EMPLOYEE BENEFIT PLANS

The information presented below covers the plans of the company and its principal subsidiaries.

Pension and Other Postretirement Benefits

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

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

The company maintains dedicated assets in support of its Supplemental Executive Retirement Plan.

During 2002, the company had amendments reflecting retiree cost of living adjustments, which resulted in an increase in the pension plan benefit obligation of $51 million. Amendments to other postretirement benefit plans related to the transfer of employees to SDG&E and changes to their specific benefits resulted in a decrease in the benefits obligation of $7 million. The amortization of these changes will affect pension expense in future years.

During 2001, the company participated in a voluntary separation program. As a result, it recorded a $13 million special termination benefit, a $1 million curtailment cost and a $19 million settlement gain.

There were no amendments to the company's pension and other postretirement benefit plans in 2003.

December 31 is the measurement date for the pension and other postretirement benefit plans.

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

(Dollars in millions)	Pension Benefits 2003	Pension Benefits 2002	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
~~CHANGE IN PROJECTED BENEFIT OBLIGATION:~~				
~~Net obligation at January 1~~	~~$ 2,290~~	~~$ 2,010~~	~~$ 797~~	~~$ 590~~
~~Service cost~~	~~52~~	~~57~~	~~19~~	~~13~~
~~Interest cost~~	~~152~~	~~149~~	~~55~~	~~42~~
~~Actuarial loss~~	~~285~~	~~197~~	~~116~~	~~191~~
~~Benefit payments~~	~~(201)~~	~~(187)~~	~~(33)~~	~~(32)~~
~~Plan amendments~~	—	~~51~~	—	~~(7)~~
~~Other~~	—	~~13~~	—	—
~~Net obligation at December 31~~	~~2,578~~	~~2,290~~	~~954~~	~~797~~
~~CHANGE IN PLAN ASSETS:~~				
~~Fair value of plan assets at January 1~~	~~1,984~~	~~2,449~~	~~409~~	~~469~~
~~Actual return on plan assets~~	~~453~~	~~(281)~~	~~90~~	~~(50)~~
~~Employer contributions~~	~~27~~	~~3~~	~~53~~	~~22~~
~~Benefit payments~~	~~(201)~~	~~(187)~~	~~(33)~~	~~(32)~~
~~Fair value of plan assets at December 31~~	~~2,263~~	~~1,984~~		

519 409

Benefit obligation, net of plan assets at December 31 (315) (306) (435) (388)

Unrecognized net actuarial loss 273 283 317 266

Unrecognized prior service cost 83 93 (13) (14)

Unrecognized net transition obligation 1 1

Net recorded asset (liability) at December 31 $ 42 $ 71 $ (131) $ (136)

The following table provides the amounts recognized on the Consolidated Balance Sheets (in Noncurrent Sundry Assets, Deferred Credits and Other Liabilities, and Postretirement Benefits Other Than Pensions) at December 31:

Other Pension Benefits Postretirement Benefits

(Dollars in millions) 2003 2002 2003 2002

Prepaid benefit cost $ 178 $ 203 $ — $ —

Accrued benefit cost (136) (132) (131) (136)

Additional minimum liability (118) (93) — —

Intangible

~~asset 9 12~~

~~Accumulated other comprehensive income, pretax 109 81~~

~~Net recorded asset (liability) $ 42 $ 71 $ (131) $ (136)~~

~~84 The accumulated benefit obligation for defined benefit pension plans was $2.4 billion and $2 billion at December 31, 2003 and 2002, respectively. The following table provides information concerning pension plans with benefit obligations in excess of plan assets as of December 31. Projected Benefit Accumulated Benefit Obligation Exceeds Obligation Exceeds the Fair Value of the Fair Value of Plan Assets Plan Assets~~

~~(Dollars in millions) 2003 2002 2003 2002~~

~~Projected benefit obligation $ 2,341 $ 2,091 $ 815 $ 736 Accumulated benefit obligation $ 2,126 $ 1,849 $ 793 $ 684 Fair value of plan assets $ 2,011 $ 1,757 $ 538 $ 468~~

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

	Pension Benefits			Other Postretirement Benefits		
(Dollars in millions)	2003	2002	2001	2003	2002	2001
Service cost	$ 52	$ 57	$ 49	$ 19	$ 13	$ 11
Interest cost	152	149	141	55	42	41
Expected return on assets	(161)	(204)	(219)	(35)	(39)	(39)
Amortization of:						
Transition obligation	1	1	1	9	9	10
Prior service cost	9	7	6	(1)	(1)	(1)
Actuarial (gain) loss	9	(18)	(39)	10	—	(3)
Special termination benefit	—	—	13	—	—	—
Curtailment cost (credit)	—	—	1	—	—	—
Settlement credit	—	—	(19)	—	—	—
Regulatory adjustment	(14)	32	51	(4)	25	30
Total net periodic benefit cost (income)	$ 48	$ 24	$ (15)	$ 53	$ 49	$ 49

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

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	6.00%	6.50%	6.00%	6.50%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31:				
Discount rate	6.50%	7.25%	6.50%	7.25%
Expected return on plan assets	7.50%	8.00%	7.30%	7.80%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

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

	2003	2002
ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31:		
Health-care cost trend rate	30.00%(1)	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	5.50%	6.50%
Year that the rate reaches the ultimate trend	2008	2004

(1) This is the weighted average of the increases for all health plans. The 2003 rate for these plans ranged from 15% to 40%.

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	$ 13	$ (11)
Effect on the health-care component of the accumulated other postretirement benefit obligation	$ 152	$ (121)

Pension Plan Investment Strategy

The asset allocation for the company's pension trust (which includes other postretirement benefit plans, except for those described below) at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31	
Asset Category	2004	2003	2002
U.S. Equity	45%	45%	44%
Foreign Equity	25%	30%	26%
Fixed Income	30%	25%	30%
Total	100%	100%	100%

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

Investment Strategy for SoCalGas' Other Postretirement Benefit Plans

The asset allocation for SoCalGas' other postretirement benefit plans at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31	
Asset Category	2004	2003	2002
U.S. Equity	70%	71%	63%
Fixed Income	30%	27%	34%
Cash	--	2%	3%
Total	100%	100%	100%

SoCalGas' other postretirement benefit plans, which are distinct from other postretirement benefit plans included in the company's pension trust (see above), are funded by cash contributions from SoCalGas and the retirees. The asset allocation is designed to match the long-term growth of the plan's liability. This plan is managed using 100% index funds.

Investment Strategy for SDG&E's Postretirement Health Plans

The asset allocation for SDG&E's postretirement health plans at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31	
Asset Category	2004	2003	2002
U.S. Equity	25%	26%	23%
Foreign Equity	5%	5%	4%
Fixed Income	70%	69%	73%
Total	100%	100%	100%

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

Future Payments

The company expects to contribute $32 million to the pension plans and $62 million to its other postretirement benefit plans in 2004.

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

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2004	$ 164	$ 35
2005	$ 167	$ 41
2006	$ 200	$ 44
2007	$ 184	$ 47
2008	$ 192	$ 49
Thereafter	$ 1,078	$ 270

Savings Plans

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

Employer contributions are invested in company stock and must remain so invested until termination of employment or until the employee's attainment of age 55, when they may be transitioned into other investments. At the direction of the employees, the employees' contributions are invested in company stock, mutual funds, institutional trusts or guaranteed investment contracts. The plans of certain non-wholly owned subsidiaries prohibit investments in Sempra Energy stock. In this case, the employer matching contributions are invested to mirror the employee-directed contributions. Employer contributions for the Sempra Energy and SoCalGas plans are partially funded by the Employee Stock Ownership Plan referred to below. Company contributions to the savings plans were $22 million in 2003, $20 million in 2002 and $17 million in 2001. The market value of company stock held by the savings plan was $675 million and $533 million at December 31, 2003 and 2002, respectively.

Employee Stock Ownership Plan

All contributions to the ESOP Trust (See Note 5) are made by the company; there are no contributions made by the participants. As the company makes contributions, the ESOP debt service is paid and shares are released in proportion to the total expected debt service. Compensation expense is charged and equity is credited for the market value of the shares released. Dividends on unallocated shares are used to pay debt service and are applied against the liability. The Trust held 2.4 million shares and 2.6 million shares, respectively, of Sempra Energy common stock, with fair values of $71.6 million and $61.0 million, at December 31, 2003 and 2002, respectively.

NOTE 9. STOCK-BASED COMPENSATION

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

In 2003, 2002 and 2001, 1,359,500, 544,100, and 777,500 shares of restricted company stock, respectively, were awarded to key employees. The corresponding weighted average market values of the shares at the time of grant were $24.42, $24.77 and $23.37, respectively. Subject to earlier forfeitures upon termination of employment, the 2003 award is scheduled to vest at the end of four years if performance-based goals are satisfied. The 2002 and 2001 awards are scheduled to vest at the end of seven years, but are also subject to earlier vesting over a four-year period upon satisfaction of objective performance-based goals. Holders of restricted stock have full voting and dividend rights except for senior officers, whose dividends are conditional. Compensation expense for the issuance of restricted stock was $16 million in 2003, $7 million in 2002 and $5 million in 2001.

In 2003, 2002 and 2001, Sempra Energy granted to officers and key employees 1,848,000, 3,444,300 and 2,934,800 stock options, respectively. The option prices were equal to the market price of common stock at the dates of grant. The options vest over four-year periods and expire 10 years from the dates of grant, subject to earlier expiration upon termination of employment. Compensation expense (or reduction thereof) for stock option grants (all associated with outstanding options with dividend equivalents that were issued before 2000 - see below) and similar awards was $6 million, ($2 million) and $7 million in 2003, 2002 and 2001, respectively.

As of December 31, 2003, 13,410,138 shares were authorized and available for future grants of restricted stock and/or stock options. In addition, on January 1 of each year, additional shares amounting to 1.5 percent of the outstanding shares of Sempra Energy common stock become available for grant.

The plans permit the granting of dividend equivalents with the stock option grants. This provides grantees the opportunity to receive some or all of the cash dividends that would have been paid on the shares since the grant date. All grants that have included dividend equivalents have made the dividend equivalents dependent on the attainment of certain performance goals. For grants prior to July 1, 1998, payment of the dividend equivalents is also contingent upon an in-the-money exercise of the related options.

In 1995, SFAS 123, "Accounting for Stock-Based Compensation," was issued. It encourages a fair-value-based method of accounting for stock-based compensation. As permitted by SFAS 123, the company adopted only its disclosure requirements and continues to account for stock-based compensation in accordance with the provisions of APB Opinion 25. See additional discussion of SFAS 148, the amendment to SFAS 123, in Note 1.

STOCK OPTION ACTIVITY

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
~~OPTIONS WITH DIVIDEND EQUIVALENTS~~			
~~December 31, 2000~~	~~4,028,573~~	~~$ 22.17~~	~~2,462,574~~
~~Exercised~~	~~(588,315)~~	~~$ 20.92~~	
~~Cancelled~~	~~(119,911)~~	~~$ 22.46~~	
~~December 31, 2001~~	~~3,320,347~~	~~$ 22.38~~	~~2,508,328~~
~~Exercised~~	~~(172,358)~~	~~$ 19.87~~	
~~Cancelled~~	~~(68,124)~~	~~$ 24.03~~	
~~December 31, 2002~~	~~3,079,865~~	~~$ 22.48~~	~~2,777,590~~

~~Exercised (876,391) $ 20.81~~
~~Cancelled (17,649) $ 24.72~~
~~Transfer (see table below) (1,536,775) $ 23.24~~

~~December 31, 2003 649,050 $ 22.89 649,050~~

~~90~~
~~Weighted Shares Average Options Under Exercise Exercisable Option Price at December 31~~

~~OPTIONS WITHOUT DIVIDEND EQUIVALENTS~~
~~December 31, 2000 7,565,421 $ 20.61 1,659,244~~
~~Granted 2,934,800 $ 22.50~~
~~Exercised (421,633) $ 18.79~~
~~Cancelled (204,134) $ 23.59~~

~~December 31, 2001 9,874,454 $ 21.19 3,143,319~~
~~Granted 3,444,300 $ 24.71~~
~~Exercised (223,430) $ 17.70~~
~~Cancelled (84,137) $ 21.70~~

~~December 31, 2002 13,011,187 $ 22.18 5,287,437~~
~~Granted 1,848,000 $ 24.44~~
~~Exercised (1,050,199) $ 20.16~~
~~Cancelled (111,906) $ 23.83~~

~~Transfer (see table above) 1,536,775 $ 23.24~~

~~December 31, 2003 15,233,857 $ 22.69 8,610,732~~

~~Additional information on options outstanding at December 31, 2003, is as follows:~~

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

~~Outstanding Options $ 16.12 — $ 19.06 3,348,195 6.04 $ 18.79 $ 20.36 — $ 22.65 5,082,028 6.14 $ 21.76 $ 23.45 — $ 27.64 7,452,684 5.12 $ 25.05~~

~~15,882,907 5.64 $ 22.68~~

~~Exercisable Options $ 16.12 — $ 19.06 2,302,520 $ 18.75 $~~

~~20.36 $~~
~~22.65~~
~~3,734,303~~
~~$ 21.50 $~~
~~23.45 $~~
~~27.64~~
~~3,222,959~~
~~$ 25.65~~
~~9,259,782~~
~~$ 22.26~~

The grant-date market value of each option grant (including dividend equivalents where applicable) was estimated using a modified Black-Scholes option-pricing model. Weighted average grant-date market values for options granted in 2003, 2002 and 2001 were $4.31, $4.45 and $4.29, respectively.

The assumptions that were used to determine these grant-date market values are as follows:

	2003	2002	2001
Stock price volatility	25%	22%	24%
Risk-free rate of return	1.8%	4.8%	4.6%
Annual dividend yield	2.2%	4.1%	4.3%
Expected life	6 Years	6 Years	6 Years

NOTE 10. FINANCIAL INSTRUMENTS

Fair Value

The fair values of certain of the company's financial instruments (cash, temporary investments, notes receivable, dividends payable, 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:

(Dollars in millions)	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in limited partnerships	$ 236	$ 352	$ 271	$ 346
First mortgage bonds	$ 1,561	$ 1,578	$ 1,386	$ 1,452
Notes payable	1,700	1,842	1,300	1,424
Equity units	600	680	600	577
SDG&E rate-reduction bonds	263	284	329	357
Debt incurred to acquire limited partnerships	110	128	145	169
Mesquite Power debt	630	630	--	--
Other long-term debt	414	436	608	623
Total long term debt	$ 5,278	$ 5,578	$ 4,368	$ 4,602

~~Due to unconsolidated affiliates $ 362* $ 392 $ 162 $ 185 -~~

~~Preferred stock of subsidiaries $ 203* $ 184 $ 204 $ 168~~

~~Mandatorily redeemable trust preferred securities $ - * $ - $ 200 $ 205~~

~~* $200 million of mandatorily redeemable trust preferred securities have been reclassified to Due to Unconsolidated Affiliates and $24 million of mandatorily redeemable preferred stock of subsidiaries have been reclassified to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets.~~

The fair values of investments in limited partnerships accounted for under the equity and cost methods were estimated based on the present value of remaining cash flows, discounted at rates available for similar investments. The fair values of debt incurred to acquire limited partnerships were estimated based on the present value of the future cash flows, discounted at rates available for similar notes with comparable maturities. The fair values of the other long-term debt, preferred stock of subsidiaries and mandatorily redeemable trust preferred securities were estimated based on quoted market prices for them or for similar issues.

Accounting for Derivative Instruments and Hedging Activities

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

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. The ineffective portion is reported in earnings immediately. The effect on other comprehensive income for the years ended December 31, 2003 and 2002 was not material. In instances where derivatives do not qualify for hedge accounting, gains and losses are recorded in the Statements of Consolidated Income.

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in commodity prices, which are subject to significant and often volatile fluctuation. Derivative instruments include futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received. The company classifies its forward contracts as follows:

Contracts that meet the definition of normal purchase and sales generally are long-term contracts that are settled by physical delivery and, therefore, are eligible for the normal purchases and sales exception of SFAS 133. The contracts are accounted for under accrual accounting and recorded in Revenues or Cost of Sales on the Statements of Consolidated Income when physical delivery occurs. Due to the adoption of SFAS 149, the company has determined that its natural gas contracts entered into after June 30, 2003 generally do not qualify for the normal purchases and sales exception.

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

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

(Dollars in millions)	2003	2002
Fixed-priced contracts and other derivatives:		
Current liabilities	$ 148	$ 153
Noncurrent liabilities	680	813
Total	828	966
Current assets	26	3
Noncurrent assets	--	42
Total	26	45
Net liabilities	$ 802	$ 921

Regulatory assets and liabilities related to derivatives held by the California Utilities are as follows:

(Dollars in millions)	2003	2002
Regulatory assets and liabilities:		
Current regulatory assets	$ 144	$ 151
Noncurrent regulatory assets	650	812
Total	794	963
Current regulatory liabilities	1	2
Net regulatory assets	$ 793	$ 961

As of December 31, 2003, the difference between net liabilities and net regulatory assets was primarily due to $30 million related to a derivative contract associated with the purchase of the Cameron LNG facility offset by $23 million related to a fixed-to-floating interest rate swap. At December 31, 2002, the difference was primarily due to market value adjustment of $42 million related to two fixed-to-floating interest rate swaps. The market value adjustment in 2002 included a reversing effect for the cancellation of one of the swap agreements on September 30, 2002. $2 million of losses in 2003 and $4 million of income in 2002 were recorded in Operating Revenues and $1 million of income in 2002 was recorded in Other Income - Net in the Statements of Consolidated Income.

Market Risk

The company's policy is to use physical and financial derivative instruments to reduce its exposure to fluctuations in interest rates, foreign currency exchange rates and commodity prices. The company also uses and trades derivative instruments in its trading and marketing of energy and other commodities. Transactions involving these instruments are with major exchanges and other firms believed to be creditworthy.

The use of these instruments exposes the company to market and credit risks, which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated.

Interest-Rate Risk Management

The company periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. This is described in Note 5.

Energy Derivatives

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in energy prices, which are subject to significant and often volatile fluctuation. Derivative instruments are comprised of futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received.

Energy Contracts

The California Utilities record transactions for natural gas and electric energy contracts in Cost of Natural Gas and Cost of Electric Fuel and Purchased Power, respectively, in the Statements of Consolidated Income. For open contracts not expected to result in physical delivery, changes in market value of the contracts are recorded in these accounts during the period the contracts are open, with an offsetting entry to a regulatory asset or liability. The majority of the California Utilities' contracts result in physical delivery, which is infrequent at the trading operations.

Sempra Energy Trading and Sempra Energy Solutions

SET derives revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum products, metals and other commodities, for which it quotes bid and ask prices to other market makers and end users. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. SET utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and often volatile fluctuation. These instruments include futures, forwards, swaps and options, and represent contracts with counterparties under which payments are linked to or derived from energy market indices or on terms predetermined by the contract, which may or may not be financially settled by SET. Sempra Energy guarantees many of SET's transactions.

SES derives a major portion of its revenue from delivering electric and natural gas supplies to its commercial and industrial customers. Such contracts are hedged to preserve margin and reduce market risk. The derivative instruments used to hedge the transactions include swaps, forwards, futures, options or combinations thereof.

Trading instruments are recorded by both SET and SES on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value with gains and losses recognized in Other Operating Revenues on the Statements of Consolidated Income. These instruments are included on the Consolidated Balance Sheets as Trading Assets or Liabilities and include amounts due from commodity clearing organizations, amounts due to or from trading counterparties, unrealized gains and losses from exchange-traded futures and options, derivative OTC swaps, forwards and options. Unrealized gains and losses on OTC transactions reflect amounts that would be received from or paid to a third party upon settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable netting arrangement. Other derivatives which qualify as hedges are accordingly recorded under hedge accounting.

As a result of the rescission of EITF 98-10 (see Note 1), energy commodity inventory is being recorded at the lower of cost or market; however metals inventories continue to be recorded at fair value in accordance with ARB No. 43. As of December 31, 2003 and 2002, trading assets included commodity inventory of $1.4 billion and $2.0 billion, respectively. Note 2 discusses SET acquisitions made in 2002, some of which were affected by EITF 98-10.

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and are carried at fair value based on closing exchange quotations. Commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and are carried at fair value derived from dealer quotations and underlying commodity exchange quotations. OTC options purchased and written are recorded on a trade-date basis. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates, as applicable.

Based on quarterly measurements, the average fair values during 2003 for trading assets and liabilities approximate $5.1 billion and $4.4 billion, respectively. For 2002, the amounts were $4.9 billion and $3.7 billion, respectively.

The carrying values of trading assets and trading liabilities approximate the following:

(Dollars in millions)	December 31, 2003	2002
TRADING ASSETS		
SET:		
Unrealized gains on swaps and forwards	$ 1,043	$ 1,226
OTC commodity options purchased	459	480
Due from trading counterparties	2,184	1,279
Due from commodity clearing organizations and clearing brokers	134	49
Commodities owned	1,420	1,968
Total	5,240	5,002
SES:		
Unrealized gains on swaps and forwards	113	96
Intercompany eliminations	(103)	(34)
Total	$ 5,250	$ 5,064
TRADING LIABILITIES		
SET:		
Unrealized losses on swaps and forwards	$ 1,095	$ 816
OTC commodity options written	226	569
Due to trading counterparties	2,195	1,196
Repurchase obligations	866	1,511
Commodities not yet purchased	56	--
Total	4,438	4,092
SES:		
Unrealized losses on swaps and forwards	35	6
Intercompany eliminations	(16)	(4)
Total	$ 4,457	$ 4,094

At SET, market risk arises from the potential for changes in the value of physical and financial instruments resulting from fluctuations in prices and basis for natural gas, electricity, petroleum, petroleum products, metals and other commodities. Market risk is also affected by changes in volatility and liquidity in markets in which these instruments are traded. Market risk for SES from fluctuations in natural gas or electricity prices is reduced by SES' hedging strategy as described above.

SET's credit risk from physical and financial instruments as of December 31, 2003 is represented by their positive fair value after consideration of collateral. Options written do not expose SET to credit risk. Exchange-traded futures and options are not deemed to have significant credit exposure since the exchanges guarantee that every contract will be properly settled on a daily basis. For SES, credit risk is associated with its retail customers.

The following table summarizes the counterparty credit quality and exposure for SET and SES at December 31, 2003 and 2002, expressed in terms of net replacement value. These exposures are net of collateral in the form of customer margin and/or letters of credit of $569 million and $240 million at December 31, 2003 and 2002, respectively.

(Dollars in millions)	December 31, 2003	December 31, 2002
Counterparty credit quality*		
SET:		
Commodity exchanges	$ 134	$ 49
AAA	5	69
AA	310	194
A	463	316
BBB	345	559
Below investment grade	357	504
Total	$ 1,614	$ 1,691
SES:		
AA	$ 6	$ 8
A	21	11
BBB	26	24
Below investment grade and not rated	68	86
Total	$ 121	$ 129

* As determined by rating agencies or internal models intended to approximate rating-agency determinations.

NOTE 11. PREFERRED STOCK OF SUBSIDIARIES

- ------------- -------------- -------------- -------------- -------------- ---- (Dollars in millions, except call/ Call/Redemption December 31, redemption price) Price 2003 2002 - --- -------------- -------------- -------------- -------------- --------------

~~Not subject to mandatory redemption: Pacific Enterprises: Without par value, authorized 15,000,000 shares: $4.75 Dividend, 200,000 shares outstanding $ 100.00 $ 20 $ 20 $4.50 Dividend, 300,000 shares outstanding $ 100.00 30 30 $4.40 Dividend, 100,000 shares outstanding $ 101.50 10 10 $4.36 Dividend, 200,000 shares outstanding $ 101.00 20 20 $4.75 Dividend, 253 shares outstanding $ 101.00~~

~~Total 80 80~~

~~SoCalGas: $25 par value, authorized 1,000,000 shares: 6% Series, 28,041 shares outstanding 1 1 6% Series A, 783,032 shares outstanding 19 19 Without par value, authorized 10,000,000 shares~~

~~Total 20 20~~

~~SDG&E: $20 par value, authorized 1,375,000 shares: 5% Series, 375,000 shares outstanding $ 24.00 8 8 4.5% Series, 300,000 shares outstanding $ 21.20 6 6 4.4% Series, 325,000 shares outstanding $ 21.00 7 7 4.6%~~

~~Series, 373,770 shares outstanding $ 20.25 7 7 Without par value: $1.70 Series, 1,400,000 shares outstanding $ 25.85 35 35 $1.82 Series, 640,000 shares outstanding $ 26.00 16 16~~

~~Total 79 79~~

~~Total not subject to mandatory redemption 179 179 Subject to mandatory redemption: SDG&E: Without par value: $1.7625 Series, 950,000 and 1,000,000 shares outstanding at December 31, 2003 and December 31, 2002, respectively $ 25.00 24* 25~~

~~Total preferred stock $ 203 $ 204~~

~~*Reclassified to Deferred Credits and Other Liabilities and to Other Current Liabilities.~~

PE preferred stock is callable at the applicable redemption price for each series, plus any unpaid dividends. The preferred stock is subject to redemption at PE's option at any time upon not less than 30 days' notice, at the applicable redemption price for each series, together with unpaid dividends. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $100 per share plus any unpaid dividends.

None of SoCalGas' preferred stock is callable. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $25 per share, plus any unpaid dividends.

All series of SDG&E's preferred stock have cumulative preferences as to dividends. The $20 par value preferred stock has two votes per share on matters being voted upon by shareholders of SDG&E and a liquidation value at par, whereas the no-par-value preferred stock is nonvoting and has a liquidation value of $25 per share, plus any unpaid dividends. SDG&E is authorized to issue 10,000,000 shares of no-par-value preferred stock (both subject to and not subject to mandatory redemption). All series are callable at December 31, 2003. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share per year from 2004 to 2007; the remaining 750,000 shares must be redeemed in 2008. On January 15, 2004, SDG&E redeemed 50,000 shares at $25 per share.

NOTE 12. SHAREHOLDERS' EQUITY AND EARNINGS PER SHARE

The only difference between basic and diluted earnings per share is the effect of common stock options. For 2003, 2002 and 2001, the effect of dilutive options was equivalent to an additional 2,742,000, 1,059,000 and 1,745,000 shares, respectively. This is based on using the treasury stock method, whereby the proceeds from the exercise price are assumed to be used to repurchase shares on the open market at the average market price for the year. The calculation excludes options covering 0.1 million, 6.0 million and 2.1 million shares for 2003, 2002 and 2001, respectively, for which the exercise price was greater than the average market price for common stock during the respective year.

Additional dilution could arise from the Equity Units described below. Through December 31, 2003, the price of the company's common stock was high enough to cause such dilution on only two days and, therefore, the Equity Units had no dilutive effect. On January 31, 2004, the common stock price was $31.14. If the price had averaged that for the full year of 2003, the Equity Units would have reduced the company's earnings per share in 2003 by $0.01.

The company is authorized to issue 750,000,000 shares of no-par-value common stock and 50,000,000 shares of preferred stock.

Excluding shares held by the ESOP, common stock activity consisted of the following:

	2003	2002	2001
Common shares outstanding, January 1	204,911,572	204,475,362	201,927,524
Common stock issuance	16,500,000	—	—
Savings plan issuance*	1,436,526	—	—
Shares released from ESOP	170,613	130,486	134,645
Stock options exercised	1,926,590	395,788	1,009,948
Long term incentive plan	1,359,500	544,100	777,500
Common stock investment plan**	728,241	212,411	762,439
Shares repurchased	(262,286)	(818,639)	(76,264)
Shares forfeited and other	(172,137)	(27,936)	(60,430)
Common shares outstanding, December 31	226,598,619	204,911,572	204,475,362

* In prior years, the plan purchased shares in the open market to cover these contributions.

** Participants in the Direct Stock Purchase Plan may reinvest dividends to purchase newly issued shares.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The CPUC's regulation of the California Utilities' capital structure limits the amounts that are available for dividends and loans to the company from the California Utilities. At December 31, 2003, SDG&E and SoCalGas could have provided a total of $290 million and $175 million, respectively, to Sempra Energy, through dividends and loans. At December 31, 2003, SDG&E and SoCalGas had loans to Sempra Energy net of intercompany payables, of $75 million and $21 million, respectively.

Equity Units

During the second quarter of 2002, the company issued $600 million of Equity Units. Each unit consists of $25 principal amount of the company's 5.60% senior notes due May 17, 2007 and a contract to purchase for $25 on May 17, 2005, between .8190 and .9992 of a share of the company's common stock (with the precise number to be determined by the then-prevailing market price). The number of shares to be issued ranges from 20 million to 24 million. The Equity Units are recorded as Long-Term Debt on the Consolidated Balance Sheets. Through December 31, 2003, $55 million had been charged to the common stock account in connection with the transaction.

Common Stock Offering

On October 14, 2003, Sempra Energy completed a common stock offering of 16.5 million shares priced at $28 per common share, resulting in net proceeds of $448 million. The proceeds were used primarily to pay off short-term debt.

NOTE 13. ELECTRIC INDUSTRY REGULATION

Background

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

SDG&E accumulated the amount that it paid for electricity in excess of the ceiling rate in an interest-bearing balancing account (the AB 265 undercollection) and began recovering these amounts in rates charged to customers following the end of the rate-ceiling period. At December 31, 2003, the AB 265 undercollection was $63 million (included in Regulatory Balancing Accounts - Net on the Consolidated Balance Sheets) and is being recovered in current rates.

Another legislative response to the power crisis resulted in the purchase by the DWR of a substantial portion of the power requirements of California's electricity users. Since early 2001, the DWR has procured power for the utility procurement customers of each of the California investor-owned utilities (IOUs) and the CPUC has established the allocation of the power and its related cost responsibility among the IOUs. Beginning on January 1, 2003, the IOUs resumed some of its electric commodity procurement, whereas previously the DWR had been purchasing the IOUs' entire net short position.

Department of Water Resources

The DWR's operating agreement with SDG&E, approved by the CPUC, governs SDG&E's administration of the allocated DWR contracts. The agreement 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 and risks associated with these activities will continue to reside with the DWR. Therefore, revenues and costs associated with the contracts were not included in the Statements of Consolidated Income during 2003. From February 2001 until December 2002, the DWR was purchasing similar amounts of power for SDG&E; the cost of that power was not included in the Statements of Consolidated Income in 2001 or 2002. The reasonableness of the IOU's administration and dispatch of the allocated contracts will be reviewed by the CPUC in an annual proceeding.

In September 2003, the CPUC approved a $1 billion refund to consumers of the three major California IOUs as a result of the DWR's lowering its revenue requirement for 2003. The refund was returned to customers in the form of a one-time bill credit. SDG&E's portion was 13.51 percent or about $135 million. The bill credit had no effect on SDG&E's net income and net cash flows because customer savings are coming from lower charges by the DWR, and SDG&E is merely transmitting the electricity from the DWR to the customers, without taking title to the electricity.

On January 8, 2004, the CPUC issued a decision on the final true-up of DWR's 2001/2002 energy costs among California's three major investor-owned electric utilities, resulting in SDG&E's customers being allocated $59 million of additional costs. The amount from this true-up is recoverable from ratepayers and will be included with SDG&E's allocated share of DWR's 2004 revenue requirement and incorporated into electric charges for 2004, which are expected to be decided in the first half of 2004. This true-up will have a short-term effect on SDG&E's cash flow but will not otherwise affect its results of operations, since SDG&E merely passes through the costs to its customers.

In October 2003, the CPUC initiated a proceeding to consider a permanent methodology for allocating DWR's Revenue Requirement beginning in 2004 through the remaining life of the DWR contracts. An interim allocation based on the current 2003 methodology was utilized beginning January 1, 2004, and is in effect until a decision is reached on a permanent methodology (expected in the second quarter of 2004). Once a permanent methodology is established, the impacts of the decision will be applied retroactively back to January 1, 2004. This delay could have an effect on SDG&E's rates and cash flows, but not on its net income.

Power Procurement

In October 2001, the CPUC initiated an Order Instituting Ratemaking (OIR) to establish ratemaking mechanisms that would enable California investor-owned electric utilities to resume purchasing electric energy and related services and hedging instruments to fulfill their obligation to serve and meet the needs of their customers. In so doing, the CPUC acknowledged that the utilities desired assurance of more timely regulatory review and cost recovery for their procurement activities and costs. In connection therewith, the OIR directed the IOUs to resume electric commodity procurement to cover their net short energy requirements by January 1, 2003. The net short position is the difference between the amount of electricity needed to cover a utility's customer demand and the power provided by owned generation and existing contracts, including the long-term DWR power contracts allocated to the customers of each IOU by the CPUC (see above).

The OIR also implemented recent legislation regarding procurement and renewables portfolio standards and establishes a process for review and approval of the utilities' long-term (20-year) procurement plans. In December 2002, the CPUC adopted SDG&E's 2003 short-term procurement plan. That plan addressed SDG&E's procurement activities in calendar year 2003, authorized contract terms for up to five years for transactions entered into under the plans, and allowed for the hedging of first quarter 2004 residual net short positions with transactions entered into in 2003. SDG&E was required to purchase approximately 10 percent of its customer requirements in 2003, based on the allocation of the DWR power approved by the CPUC in December 2002. The CPUC authorized SDG&E to acquire a variety of resource types and demand side resources. A semiannual cost review and rate revision mechanism is established, and a trigger is established for more frequent changes if undercollected commodity costs exceed five percent of annual, non-DWR generation revenues, to provide for timely recovery of any undercollections. Approval of SDG&E's 2003 short-term procurement plan provided for SDG&E's return to procurement of its customers' needs on January 1, 2003, consistent with the intent of the legislature and the CPUC.

SDG&E filed its 20-year long-term resource plan covering its anticipated procurement needs between 2004 and 2023 and its short-term procurement plans for its anticipated procurement activities in 2004. In decisions issued in December 2003 and January 2004, the CPUC approved the 2004 procurement plan and provided policy guidance for the filing of an updated 20-year resource plan in the spring of 2004.

On December 18, 2003, the CPUC issued a decision adopting SDG&E's procurement plan for 2004. The decision delayed until 2004 further CPUC direction on comprehensive policy guidance for the IOUs' long-term resource plans. In the decision, the CPUC continued its moratorium (subject to certain exceptions) on the IOUs' ability to deal with their own affiliates in procurement transactions.

SDG&E's 20-year resource plan identified the near-term need for firm capacity resources within its service territory to support transmission grid reliability. As a result, SDG&E issued a Request for Proposals (RFP) for the years 2005-2007 of 69 MW in 2005 increasing to 291 MWs in 2007.

In October 2003, SDG&E filed a motion in the Procurement OIR that now requests the CPUC to authorize SDG&E to enter into five new electric resource contracts. They include:

The 550-megawatt combined-cycle Palomar power plant in Escondido, California to be constructed by SER for completion in 2006.

The 45-MW Ramco combustion turbine which SDG&E is proposing to acquire as a turnkey project and intends to use for intermediate load requirements beginning June 2005.

(SDG&E will not take ownership of these two facilities unless appropriate cost recovery and ratemaking mechanisms are instituted by the CPUC to ensure that SDG&E recovers all reasonable costs of, and a reasonable return on, the investments.)

A power purchase agreement (PPA) to buy up to 570 MW over ten years starting in 2008 from a power plant that Calpine Corporation (Calpine) would complete on its site within SDG&E's service territory. (SDG&E would recommend the Calpine PPA only if the CPUC orders the implementation of certain critical conditions intended to make the Calpine PPA a positive economic benefit to SDG&E's customers.)

One contract each for a demand-response resource and a renewable resource.

The capital cost related to the five contracts proposed by SDG&E is $640 million. Hearings concluded on February 20, 2004, and a decision is expected in May 2004. Given the CPUC's prior denial of the company's request for approval of additional transmissions facilities, the company believes that customer requirements for electricity could not be met without the requested resources or similar additions.

A June 2003 CPUC decision in the Procurement OIR directed each IOU to procure from renewable sources at least one percent of its 2003 total energy sales, increasing to 20 percent by 2017. SDG&E procured four percent of its 2003 total energy sales from renewable sources and existing contracts will increase this to five percent in 2004 and nine percent in 2007. A 2002 CPUC resolution permits the company to credit toward future years' compliance any excess over its one-percent annual requirement.

On July 11, 2003, the CPUC adopted a proposed decision continuing the level of the Direct Access (DA) cost responsibility surcharge (CRS) cap effective July 1, 2003 at 2.7 cents per kilowatt hour (kWh), subject to possible revision in the next DA CRS cap review proceeding. In each periodic DA CRS cap review proceeding, the cap is subject to adjustment to the extent necessary to maintain the goal of refunding to utility customers the full amounts to which they are entitled by the end of the DWR contract term in 2011. The DA CRS has no impact on SDG&E; however, the surcharge may affect SES' ability to attract and maintain customers in California.

SONGS

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

FERC Actions

DWR Contract

On June 25, 2003, the FERC issued orders upholding the company's long-term energy supply contract with the DWR, as well as contracts between the DWR and other power suppliers. The order affirmed a previous FERC conclusion that those advocating termination or alteration of the contract would have to satisfy a "heavy" burden of proof, and cited its long-standing policy to recognize the sanctity of contracts. In the order, the CPUC noted that CPUC and court precedent clearly establish that allegations that contracts have become uneconomic by the passage of time do not render them contrary to the public interest under the Federal Power Act. The CPUC pointed out that the contracts were entered into voluntarily in a market-based environment. The CPUC found no evidence of unfairness, bad faith or duress in the original contract negotiations. It said there was no credible evidence that the contracts placed the complainants in financial distress or that ratepayers will bear an excessive burden. In December 2003, appeals of this matter filed by a number of parties, including the California Energy Oversight Board and the CPUC, were consolidated and assigned to the Ninth Circuit Court of Appeals (the Court). The company expects that the Court will affirm the FERC decision.

Refund Proceedings

The FERC is investigating prices charged to buyers in the PX and ISO markets by various electric suppliers. The FERC is seeking to determine the extent to which individual sellers have yet to be paid for power supplied during the period of October 2, 2000 through June 20, 2001 and to estimate the amounts by which individual buyers and sellers paid and were paid in excess of competitive market prices. Based on these estimates, the FERC could find that individual net buyers, such as SDG&E, are entitled to refunds and individual net sellers, such as SET, are required to provide refunds. To the extent any such refunds are actually realized by SDG&E, they would reduce SDG&E's rate-ceiling balancing account. To the extent that SET is required to provide refunds, they could result in payments by SET after adjusting for any amounts still owed to SET for power supplied during the relevant period (or receipts if refunds are less than amounts owed to SET).

In December 2002, a FERC Administrative Law Judge (ALJ) issued preliminary findings indicating that the California PX and ISO owe power suppliers $1.2 billion (the $3.0 billion that the California PX and ISO still owe energy companies less $1.8 billion that the energy companies charged California customers in excess of the preliminarily determined competitive market clearing prices). On March 26, 2003, the FERC largely adopted the ALJ's findings, but expanded the basis for refunds by adopting a staff recommendation from a separate investigation to change the natural gas proxy component of the mitigated market clearing price that is used to calculate refunds. The March 26 order estimates that the replacement formula for estimating natural gas prices will increase the refund obligations from $1.8 billion to more than $3 billion. The FERC recently released its final instructions, and ordered the ISO and PX to recalculate the precise number through their settlement models. California is seeking $8.9 billion in refunds from its electricity suppliers and has appealed the FERC's preliminary findings and requested rehearing of the March 26 order. SET and other power suppliers have joined in appeal of the FERC's preliminary findings and requested rehearing.

SET had established reserves of $29 million for its likely share of the original $1.8 billion. SET is unable to determine its possible share of the additional refund amount. Accordingly, it has not recorded any additional reserves but the company does not believe that any additional amounts that SET may be required to pay would be material to the company's financial position or liquidity.

Manipulation Investigation

The FERC is also investigating whether there was manipulation of short-term energy markets in the West that would constitute violations of applicable tariffs and warrant disgorgement of associated profits. In this proceeding, the FERC's authority is not confined to the October 2, 2000 through June 20, 2001 period relevant to the refund proceeding. In

May 2002, the FERC ordered all energy companies engaged in electric energy trading activities to state whether they had engaged in various specific trading activities in violation of the PX and ISO tariffs (generally described as manipulating or "gaming" the California energy markets).

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. First, FERC directed 43 entities, including SET and SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. Second, the FERC directed more than 20 entities, including SET, to show cause why their activities during the period January 1, 2000 to June 20, 2001 did not constitute gaming and/or anomalous market behavior in violation of the tariffs. Remedies for confirmed violations could include disgorgement of profits and revocation of market-based rate authority. The FERC has encouraged the entities to settle the issues and on October 31, 2003, SET agreed to pay $7.2 million in full resolution of these investigations. The entire amount has been recorded as of December 31, 2003. The entire proceeding, including the settlement, is subject to final approval by the FERC, which is expected during 2004. SDG&E and the FERC resolved the matter by SDG&E's paying $28 thousand into a FERC-established fund.

On June 25, 2003, the FERC also determined that it was appropriate to initiate an investigation into possible physical and economic withholding in the California ISO and PX markets. For the purpose of investigating economic withholding, the FERC used an initial screen of all bids exceeding $250 per MW between May 1, 2000 and October 2, 2001. Both SDG&E and SET have received data requests from the FERC staff and have provided responses. The FERC staff will prepare a report to the FERC, which will be the basis to decide whether additional proceedings are warranted. SET and SDG&E believe that their bids and bidding procedures were consistent with ISO and PX tariffs and protocols and applicable FERC price caps. On August 1, 2003, the FERC staff issued an initial report that determined there was no need to further investigate particular entities, including SET, for physical withholding of generation.

NOTE 14. OTHER REGULATORY MATTERS

Natural Gas Industry Restructuring

In December 2001 the CPUC issued a decision related to natural gas industry restructuring (GIR), with implementation anticipated during 2002. On January 12, 2004, after many delays and changes, an ALJ issued a proposed decision that would implement the 2001 decision. The proposed decision would result in revising noncore balancing account treatment to exclude the balancing of SoCalGas' transmission costs; other noncore costs/revenues would continue to be fully balanced until the decision in the next Biennial Cost Allocation Proceeding (BCAP) (see below). On February 11, 2004, a member of the CPUC issued an alternative decision that would vacate the December 2001 decision and defer GIR matters to the Natural Gas Market OIR (see below). A CPUC decision could be issued in March 2004.

Natural Gas Market OIR

The Natural Gas Market OIR was approved on January 22, 2004, and will be addressed in two concurrent phases. The schedule calls for a Phase I decision by summer 2004 and a Phase II decision by the end of 2004. In Phase I the CPUC's objective is to develop a process enabling the CPUC to review and pre-approve new interstate capacity contracts before they are executed. In addition, the California Utilities must submit proposals on any LNG project to which interconnection is planned, providing costs and terms, including access to the pipelines in Mexico. Phase II will primarily address emergency reserves and ratemaking policies. The OIR invites proposals on how utilities should provide emergency reserves consisting of slack intrastate pipeline capacity, contracts for additional capacity on the interstate pipelines and an emergency supply of natural gas storage. The CPUC's objective in the ratemaking policy component of Phase II is to identify and propose changes to policies that create incentives that are consistent with the goal of providing adequate and reliable long-term supplies and that do not conflict with energy efficiency programs. The focus of the Gas OIR is 2006 to 2016. Since GIR (see above) would end in August 2006 and there is overlap between GIR and the Gas OIR issues, a number of parties (including SoCalGas) are advising the CPUC not to implement GIR.

The company believes that regulation needs to consider sufficiently the adequacy and diversity of supplies to California, transportation infrastructure and cost recovery thereof, hedging opportunities to reduce cost volatility, and programs to encourage and reward conservation.

Cost of Service

The California Utilities have filed cost of service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs. The California Utilities are requesting revenue increases of $121 million. The CPUC's Office of Ratepayer Advocates (ORA) filed its prepared testimony on the applications in August 2003, recommending numerous rate decreases that would reduce annual revenues by $162 million from their current level. The Utility Consumers' Action Network (UCAN), a consumer-advocacy group, has proposed rates for SDG&E and The Utility Reform Network has proposed rates for SoCalGas that would reduce annual revenues by $88 million and $178 million, respectively, from their current level. Hearings concluded in November 2003. On December 19, 2003, settlements were filed with the CPUC that, if approved, would resolve most of the cost of service issues. The SoCalGas settlement was signed by SoCalGas and all parties active in its application. The SDG&E settlement was signed by SDG&E, ORA and other parties, but not by UCAN, the City of Chula Vista and other parties. The CPUC adopted a schedule for briefing and commenting on the proposed settlements that concluded on February 19, 2004. The SoCalGas settlement would reduce rates by $33 million from 2003 rates. The SDG&E settlement would reduce its electric rates by $19.6 million from 2003 rates and increase its natural gas rates by $1.8 million from 2003 rates. As part of the proposed settlement, SDG&E and the ORA would resolve their dispute concerning the allocation of the gain on sale of SDG&E's surplus property in Blythe, California, by increasing SDG&E's forecast of miscellaneous revenues by $1.3 million annually, thereby lowering its retail revenue requirement by that amount. The CPUC may accept one or both of the settlements or may adopt an outcome differing from both of the settlements. Resolution is likely in the second quarter of 2004.

On December 18, 2003, the CPUC issued a decision that creates memorandum accounts as of January 1, 2004, to record the difference between actual revenues and those that are later authorized in the CPUC's final decision in this case. The difference would then be amortized in rates. The California Utilities have also filed for continuation through 2004 of existing performance-based regulation (PBR) mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but deferred action on applying any rewards or penalties for performance relative to these targets to a decision to be issued later in 2004 in a second phase of these applications discussed below.

The CPUC has established a procedural schedule for the second phase of these applications, addressing issues related to PBR (see below). The procedural schedule calls for hearings to be held in June 2004, with a decision during 2004. The scope of the second phase includes: (a) a formula for setting authorized cost of service for 2005 and succeeding years until the next full Cost of Service proceeding is scheduled; (b) whether and how rates should be adjusted if earned returns vary from authorized returns; and (c) prospective targets and rewards/penalties for service quality and safety.

An October 2001 decision denied the California Utilities' request to continue equal sharing between ratepayers and shareholders of the estimated savings for the 1998 business combination that created Sempra Energy and, instead, ordered that all of the estimated 2003 merger savings go to ratepayers. In 2002, merger savings to shareholders for the fourth quarter and for the year were $4 million and $17 million, respectively, at SoCalGas and $2 million and $8 million, respectively, at SDG&E. Pursuant to the decision, SoCalGas and SDG&E will return the 2003 merger savings related to natural gas operations of $83 million and $15 million, respectively, to ratepayers over a twelve-month period beginning January 1, 2004. The merger savings related to electric operations were previously returned to ratepayers.

Performance-Based Regulation

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC adopted PBR for SDG&E effective in 1994 and for SoCalGas effective in 1997. PBR has resulted in modification to the general rate case and certain other regulatory proceedings for the California Utilities. Under PBR, regulators require future income potential to be tied to achieving or exceeding specific performance and productivity goals, rather than relying solely on expanding utility plant to increase earnings.

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

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

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

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

In July 2003, the CPUC issued a decision relative to SDG&E's Year 11 natural gas PBR application, which will permanently extend the PBR mechanism with some modification. The decision approved the Joint Parties' Motion for an Order Adopting Settlement Agreement filed by SDG&E and the ORA, which will apply to Year 10 and beyond. The effect of the modifications is to reduce slightly the potential size of future PBR rewards or penalties.

The Gas Cost Incentive Mechanism (GCIM) allows SoCalGas to receive a share of the savings it achieves by buying natural gas for customers below monthly benchmarks. The mechanism permits full recovery of all costs within a tolerance band above the benchmark price and refunds savings within a tolerance band below the benchmark price. The costs outside the tolerance band are shared between customers and shareholders.

Since the 1990s, IOUs have been eligible to earn awards for implementing and administering energy conservation and efficiency programs. The California Utilities have offered these programs to customers and have consistently achieved significant earnings from the program. On October 16, 2003, the CPUC issued a decision that the pre-1998 DSM earnings proceeding would not be reopened, leaving the earnings mechanism unchanged. The CPUC may adjust amounts determined pursuant to the earnings mechanism consistent with the application of known, standard measurement and verification protocols.

The CPUC has consolidated the 2000, 2001 and 2002 award applications. The 2003 award applications were filed on May 1, 2003. On May 2, 2003, the CPUC released RFPs to conduct a review of the IOUs' studies and reported program milestones/accomplishments used as the basis for the awards claims and program expenditures. The review should be completed in the second quarter of 2004. Additionally, the low-income awards will be subject to an independent review expected to commence in 2005. The majority of the outstanding claims are on hold pending completion of the independent review.

Incentive Awards Approved in 2003

PBR and GCIM rewards are not included in the company's earnings before CPUC approval is received. The following table reflects awards approved in 2003 (dollars in millions):

Program	SoCalGas	SDG&E	Total
GCIM/Natural Gas PBR	$ 48.2	$ 5.3	$ 53.5
Distribution/Other PBR	1.1	18.2	19.3
Total	$ 49.3	$ 23.5	$ 72.8

Pending Incentive Awards

At December 31, 2003, the following performance incentives were pending CPUC approval and, therefore, were not included in the company's earnings (dollars in millions):

Program	SoCalGas	SDG&E	Total
GCIM/Natural Gas PBR	$ 6.3	$ 1.9	$ 8.2
DSM/Energy Efficiency*	9.8	35.6	45.4
Total	$ 16.1	$ 37.5	$ 53.6

* Dollar amounts shown do not include interest, franchise fees or uncollectible amounts.

Cost of Capital

Effective January 1, 2003, SoCalGas' authorized rate of return on common equity (ROE) is 10.82 percent and its return on ratebase (ROR) is 8.68 percent. Effective January 1, 2003, SDG&E's authorized ROE is 10.9 percent and its ROR is 8.77 percent, for SDG&E's electric distribution and natural gas businesses. The electric-transmission cost of capital is determined under a separate FERC proceeding discussed below. These rates will continue to be effective until market interest-rate changes are large enough to trigger an automatic adjustment or until the CPUC orders a periodic review.

The objective of SDG&E's market-indexed capital adjustment mechanism is to revise SDG&E's rates to reflect changes in the six-month average of double-A rated utility bond rates, without lengthy Commission proceedings. The benchmark average is currently 7.24 percent, the six-month average at September 30, 2002, the year of SDG&E's last cost of capital proceeding. If in any year the difference between the current six-month average at September 30th and the benchmark exceeds 100 basis points, SDG&E's authorized ROE is adjusted by one-half of the difference, and the embedded costs of debt and preferred equity are adjusted to current levels. In addition, the triggering six-month average becomes the new benchmark until another automatic adjustment occurs. The six-month average was 6.32 percent at September 30, 2003 and, therefore, no triggering has occurred. The rate has not changed significantly since then.

SoCalGas' automatic adjustment mechanism provides for a trigger in any month when the 12-month trailing average of 30-year Treasury bond rates varies by greater than 150 basis points from the benchmark, and the current Global Insight forecast of the 30-year Treasury bond rate 12 months ahead varies by greater than 150 basis points from the benchmark. When these criteria are met, SoCalGas' authorized ROE is adjusted by one-half of the difference between the trailing 12-month average and the benchmark, and the embedded costs of debt and preferred equity are adjusted to current levels. Any time an automatic adjustment occurs, the new trailing 12-month average becomes the new benchmark. The benchmark is currently 5.38 percent, the 12-month trailing average of the 30-year Treasury bond as of October 2002. At December 31, 2003, the 12-month average of the 30-year Treasury bond was 4.92 percent and the estimated Global Insight year-ahead forecast was 5.90 percent and, therefore, no triggering has occurred. The rates have not changed significantly since then.

Border Price Investigation

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California-Arizona border between March 2000 and May 2001. If the investigation determines that the conduct of any party to the investigation contributed to the natural gas price spikes, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. On December 10, 2003, Southern California Edison filed testimony alleging that SoCalGas significantly contributed to the price spikes and exercised market power and recommended to the CPUC that SoCalGas divest its storage assets and revise its GCIM to an incentive mechanism that would simply reward SoCalGas if it managed to procure natural gas supplies in the producing basins at a price below market. Hearings are scheduled to begin in late March 2004 with a decision expected by late 2004. The company believes that the CPUC will find that SoCalGas acted in the best interests of its core customers.

Biennial Cost Allocation Proceeding

The BCAP determines the allocation of authorized costs between customer classes for natural gas transportation service provided by the California Utilities and adjusts rates to reflect variances in customer demand as compared to the forecasts previously used in establishing transportation rates. SoCalGas and SDG&E filed with the CPUC their 2005 BCAP applications in September 2003, requesting updated transportation rates effective January 1, 2005. The most recent BCAP decision allocating the California Utilities non-commodity natural gas costs of service and revising their respective natural gas transportation rates and rate designs was issued in April 2000 and is still in effect. In November 2003, an Assigned Commissioner Ruling delayed the current BCAP applications until a decision is issued in the GIR implementation proceeding discussed above. As a result, SoCalGas is required to amend its BCAP application within 21 days of a decision in the GIR and SDG&E

is required to amend its BCAP application seven days thereafter. As a result of the deferrals and the forecasted significant decline in noncore gas throughput on SoCalGas' system, in December 2002 the CPUC issued a decision approving 100 percent balancing account protection for SoCalGas' risk on local transmission and distribution revenues from January 1, 2003 until the CPUC issues its next BCAP decision. SoCalGas is seeking to continue this balancing account protection through 2006. A CPUC decision on GIR could result in revising noncore balancing account treatment to exclude the balancing of transmission costs; other noncore costs/revenues would continue to be fully balanced until the BCAP decision.

CPUC Investigation of Energy-Utility Holding Companies

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. Among the matters to be considered in the investigation are utility dividend policies and practices and obligations of the holding companies to provide financial support for utility operations under the agreements with the CPUC permitting the formation of the holding companies. In January 2002 the CPUC issued a decision to clarify under what circumstances, if any, a holding company would be required to provide financial support to its utility subsidiaries. The CPUC broadly determined that it would require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to cover their utility subsidiaries' capital requirements, as the IOUs have previously acknowledged in connection with the holding companies' formations. In January 2002 the CPUC ruled on jurisdictional issues, deciding that it had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed. The company's request for rehearing on the issues was denied by the CPUC and the company subsequently filed appeals in the California Court of Appeal. On November 26, 2003 the California Court of Appeal agreed to hear the company's appeal. Oral argument is set for March 5, 2004.

CPUC Investigation of Compliance with Affiliate Rules

In February 2003, the CPUC opened an investigation of the business activities of SDG&E, SoCalGas and Sempra Energy to determine if they have complied with statutes and CPUC decisions in the management, oversight and operations of their companies. In September 2003, the CPUC suspended the procedural schedule until it completes an independent audit to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of SDG&E and SoCalGas. The audit will cover years 1997 through 2003, is expected to commence in March 2004 and should be completed by the end of 2004. The scope of the audit will be broader than the annual affiliate audit. In accordance with existing CPUC requirements, the California Utilities' transactions with other Sempra Energy affiliates have been audited by an independent auditing firm each year, with results reported to the CPUC, and there have been no material adverse findings in those audits.

FERC Standards of Conduct

On November 25, 2003, the FERC established standards of conduct governing the relationship between transmission providers and their energy affiliates. They broaden the definition of an energy affiliate. Under the standards, SDG&E is a transmission provider and SoCalGas is an energy affiliate of SDG&E. The standards require transmission providers to offer service to all customers on a non-discriminatory basis. SER, SES and SET are also considered energy affiliates of SDG&E, and, among other things, SDG&E must apply the standards of conduct prohibiting unduly preferential information sharing with the energy affiliates. Impacts, if any, of the standards are being determined for SEI and SER.

FERC Transmission Cost of Service

On May 2, 2003, the FERC accepted SDG&E's request for modification of its Transmission Owner Tariff to adopt a transmission rate formula that would allow SDG&E to recover its actual prudent costs for transmission service. New transmission rates, which are subject to refund based on the FERC's final order, became effective October 1, 2003.

On December 18, 2003, the FERC approved the transmission formula, with rates effective October 1, 2003, whereby SDG&E's rates would be adjusted annually to cover actual prudent costs, including an ROE of 11.25 percent on its actual equity as of December 31 of the prior year. SDG&E's revenue requirements for its retail customers for the initial 12-month period beginning October 1, 2003, will be $142.1 million. SDG&E will fully recover its cancelled Valley-Rainbow Project costs of $19 million over a ten-year amortization period, with no return component. The transmission rate formula will be in effect through June 30, 2007.

Recovery of Certain Disallowed Transmission Costs

In August 2002 the FERC issued Opinion No. 458, which effectively disallowed SDG&E's recovery of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink under the Participation Agreements and charges assessed to SDG&E under the ISO FERC tariff for transmission line losses and grid management charges related to energy schedules of Arizona Public Service Co. (APS) and the Imperial Irrigation District (IID), its Southwest Powerlink co-owners. As a result, SDG&E is incurring unreimbursed costs of $4 million to $8 million per year. On November 17, 2003, SDG&E petitioned the United States Court of Appeals for review of these FERC orders and argued that the disallowed costs should be allowed for recovery through the Transmission Revenue Balancing Account Adjustment. On February 12, 2004, on the FERC's motion, the court remanded the case back to the FERC for further consideration, "based on the FERC's representation that it intends to act expeditiously on remand." The FERC has not yet issued further orders in this matter.

In a separate but related matter, on July 6, 2001, SDG&E filed an arbitration claim against the ISO, claiming the ISO should not charge SDG&E for the transmission losses attributable to energy schedules on the APS and IID shares of the Southwest Powerlink. As of October 2003 amounts under the claim totaled $22 million, including interest. The independent arbitrator found in SDG&E's favor on this matter. The ISO appealed this result to the FERC and a FERC decision is expected in

2004. SDG&E has also commenced a private arbitration to reform the Participation Agreements to remove prospectively SDG&E's obligation to provide services giving rise to unreimbursed ISO tariff charges.

Southern California Fires

Several major wildfires that began on October 26, 2003 severely damaged some of SDG&E's infrastructure, causing a significant number of customers to be without utility services. On October 27, 2003, Governor Gray Davis declared a "state of emergency" for counties within SoCalGas' and SDG&E's service territory.

The declaration of a state of emergency authorizes a public utility to establish a catastrophic event memorandum account (CEMA) to record all incremental costs (costs not already included in rates) associated with the repair of facilities and the restoration of service. Electric distribution and natural gas related costs are recovered through the CEMA. Electric transmission related costs are recovered through the annual true-up FERC proceeding. The CEMA related costs are recoverable in rates separate from ordinary costs currently recovered in rates. The CPUC is required to hold expedited hearings in response to the utilities' request for recovery. Total fire-related costs are estimated to be $70 million and $5 million for SDG&E and SoCalGas, respectively, with $60 million and $1 million, respectively, incurred during 2003, the majority of which were capital related. At December 31, 2003, the CEMA account included $14 million of incremental operating and maintenance costs. The company expects to file a CEMA application sometime in 2004. The company expects no significant effect on earnings from the fires.

NOTE 15. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The California Utilities buy natural gas under short-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. The California Utilities transport natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. SoCalGas has commitments with pipeline companies for firm pipeline capacity under contracts that expire at various dates through 2007.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines that expire on various dates between 2004 and 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues its ongoing assessment of its long-term pipeline capacity portfolio, including the release of a portion of this capacity to third parties.

At December 31, 2003, the future minimum payments under natural gas contracts were:

(Dollars in millions)	Storage and Transportation	Natural Gas	Total
2004	$ 221	$ 767	$ 988
2005	211	11	222
2006	125	11	136
2007	21	2	23
2008	20	3	23
Thereafter	207		207
Total minimum payments	$ 805	$ 794	$1,599

Total payments under natural gas contracts were $2.2 billion in 2003, $1.4 billion in 2002 and $2.6 billion in 2001.

Purchased-Power Contracts

In January 2001, the California Assembly passed AB X1 to allow the DWR to purchase power under long-term contracts for the benefit of California consumers. In accordance with AB X1, SDG&E entered into an agreement with the DWR under which the DWR purchased SDG&E's full net short position (the power needed by SDG&E's customers, other than that provided by SDG&E's nuclear generating facilities or its previously existing purchased-power contracts) through December 31, 2002. Starting on January 1, 2003, SDG&E and the other IOUs resumed their electric commodity procurement function based on a CPUC decision issued in October 2002. In April 2003, the CPUC approved an operating agreement between the DWR and SDG&E that bestows upon SDG&E the role of a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions for the DWR contracts. For additional discussion of this matter see Note 13.

For 2004, SDG&E expects to receive 49 percent of its customer power requirement from DWR allocations. Of the remaining requirements, SONGS is expected to account for 21 percent, long-term contracts for 19 percent and spot market purchases for 11 percent. The contracts expire on various dates through 2025. Prior to January 1, 2001, the cost of these contracts was recovered by bidding them into the PX and receiving revenue from the PX for bids accepted. As of January 1, 2001, in compliance with a FERC order prohibiting sales to the PX, SDG&E no longer bids those contracts into the PX. Those contracts are now used to serve customers in compliance with a CPUC order. In addition, during 2002 SDG&E entered into contracts which will provide five percent of its 2004 total energy sales from renewable sources. These contracts expire on various dates through 2021.

At December 31, 2003, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)	
2004	$ 214
2005	224
2006	233
2007	240
2008	218
Thereafter	2,235
Total minimum payments	$ 3,364

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Excluding DWR-allocated contracts, total payments under the contracts were $396 million in 2003, $235 million in 2002 and $512 million in 2001.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2004 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 3 percent to 6 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company. The company also has long-term capital leases on real property. Property, plant and equipment included $36 million at December 31, 2003 and $35 million at December 31, 2002, related to these leases. The associated accumulated amortization was $23 million and $21 million, respectively. SDG&E terminated its capital lease agreement for nuclear fuel in mid-2001 and now owns its nuclear fuel.

At December 31, 2003, the minimum rental commitments payable in future years under all noncancellable leases were as follows:

(Dollars in millions)	Operating Leases	Capitalized Leases
2004	$ 97	$ 4
2005	85	3
2006	77	1
2007	76	1
2008	69	1
Thereafter	213	1
Total future rental commitments	$ 617	11
Imputed interest (6% to 10%)		(3)
Net commitments		$ 8

In connection with the quasi-reorganization described in Note 1, PE recorded liabilities of $102 million to adjust to fair value the operating leases related to its headquarters and other facilities at December 31, 1992. The remaining amount of these liabilities was $35 million at December 31, 2003. These leases are included in the above table at the amounts provided in the lease.

Rent expense for operating leases totaled $98 million in 2003, $90 million in 2002 and $92 million in 2001. Depreciation expense for capitalized leases is included in Depreciation and Amortization on the Consolidated Statements of Income.

Global Construction Projects

Global has several subsidiaries which have developed or are in the process of constructing various capital projects in the United States and in Mexico. The following is a summary of construction projects developed or under development by the respective business units.

SER

SER acquires, develops and operates power plants throughout the U.S. and Mexico. As of the end of 2003, SER had five power plants in operations.

The 1,250-MW Mesquite Power plant commenced operations in two phases during 2003; the first phase of commercial operations began in June 2003 and the second phase started in December 2003. See further discussion on the Mesquite Power plant in Notes 1 and 2.

In the third quarter of 2003, SER completed construction and commenced operations of its $350 million 600-MW TDM power plant. The environmental issues concerning this facility are described under "Litigation" and in Note 2. TDM's natural gas from Ehrenberg, Arizona to the interconnection with Gasoducto Bajanorte is being delivered via the North Baja Pipeline. The transportation is provided through an agreement between SER and North Baja Pipeline LLC. Under the agreement, SER is obligated to pay a monthly reservation charge for the transport of certain quantities over a 20-year period. The future commitments related to this contract are $83 million.

In the third quarter of 2003, SER completed construction of the 550-MW Elk Hills power project located in Bakersfield, California. SER owns 50 percent of Elk Hills and has invested $219 million in Elk Hills through December 31, 2003.

On October 31, 2002, SER acquired the 305-MW Twin Oaks Power plant. In connection with the acquisition, SER also assumed a contract which includes annual commitments to purchase lignite coal either until an aggregate minimum volume has been achieved or through 2025. As of December 31, 2003, SER's future minimum payments under the lignite coal agreement totaled $455 million, for which payments of $29 million are due for 2004, $29 million for 2005, $25 million for 2006, $25 million for 2007, $25 million for 2008 and $322 million thereafter. The minimum payments have been adjusted for allowed shortfalls and 90 percent minimum contract requirements under the contract.

In August 2003, SER obtained approvals by the California Energy Commission for the company's planned 550-MW Palomar power plant in Escondido, California. The estimated two-year construction project will commence when power contracts for the project have been signed. SER currently is seeking contracts that would support advancement of the project. In January 2004, SDG&E contracted with SER to purchase the power plant from SER when construction is complete in 2006. The plant will then be owned and operated by SDG&E under CPUC regulation.

As of December 31, 2003, SER has no additional construction commitments concerning the facilities described above but has additional commitments of $7 million related to two natural gas turbines for use in future power plant development.

SELNG

SELNG is in the process of developing Energia Costa Azul, a major new LNG receiving terminal that will bring natural gas supplies into northwestern Mexico and Southern California. This is discussed in Note 2.

In April 2003, SELNG acquired Cameron LNG for $36 million. Additional payments are contingent on meeting certain benchmarks and milestones and the performance of the project. At December 31, 2003, the company has recorded a liability of $30 million related to this matter. The total cost of the project is expected to be about $700 million. The project could begin commercial operations as early as 2007.

SELNG currently leases land in Hackberry, Louisiana for the development of the Cameron LNG terminal. In connection with the purchase of Cameron LNG, SELNG and the lessor agreed to certain lease amendments, including an increase in the annual rent, addition of wharfage fees and extension of the lease term for another 30 years. The lease amendments are contingent upon obtaining project financing or commencement of construction. As of December 31, 2003, SELNG is still operating under the original land lease, which is up for renewal in February 2005. Accordingly, rent payments subsequent to January 2005 are not included in the table of future minimum rental payment obligations. Should the terms of the amended lease be triggered, total rent payments and wharfage fees would be $38 million over 30 years. See Note 2 for further discussion on the LNG facilities.

SEI

In 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with a pipeline built by PG&E Corporation (PG&E) that connects to Arizona. The 30-inch pipeline can deliver up to 500 million cubic feet per day of natural gas to new generation facilities in Baja California, including SER's TDM power plant discussed above. Capacity on the pipeline is over 90 percent subscribed. The company had no additional construction costs or other commitments for this pipeline at December 31, 2003.

SER's Contract with DWR

In May 2001, SER entered into a ten-year agreement with the DWR to supply up to 1,900 MW of power to the state. SER may, but is not obligated to, deliver this electricity from its portfolio of plants in the western United States and Baja California, Mexico. If SER elects to use these plants to supply the DWR, those sales would comprise more than two-thirds of the projected capacity of the plants. Subsequent to the state's signing of this contract and electricity-supply contracts with other vendors, various state officials have contended that the rates called for by the contracts are too high. These rates substantially exceed current spot-market prices for electricity, but are substantially lower than those prevailing at the time the contracts were signed. Information concerning the validity of this contract is provided under "Litigation - DWR Contract." Information concerning the FERC's orders upholding this contract and the pending appeal is provided in FERC Actions in Note 13.

Impact of Direct Access on SES

On March 21, 2002, the CPUC affirmed its decision prohibiting new direct access contracts after September 20, 2001, but rejected a proposal to make the prohibition retroactive to July 1, 2001. Contracts in place as of September 20, 2001 may be renewed or assigned to new parties. On November 7, 2002, the CPUC issued a decision adopting DA exit fees with an interim cap of 2.7 cents per kWh for rates effective January 1, 2003. The CPUC is conducting further proceedings to determine whether, and to what extent, the interim cap should be revised after July 1, 2003. The CPUC's decisions concerning direct access could affect the motivation of potential customers to enter into contracts for SES to sell them electricity in California.

Environmental Issues

The company has identified no significant environmental issues outside the United States, except for the additional environmental impact studies the DOE is conducting of the TDM power plant. Additional information regarding the environmental studies is provided below under "Litigation." The following discussion is related to environmental matters within the United States.

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. Most of the environmental issues faced by the company have occurred at the California Utilities. However, now that SER owns and operates several power plants and SELNG is developing LNG regasification terminals, additional environmental issues may arise. As applicable, appropriate and relevant, these laws and regulations require that the company investigate and remediate the effects of the release or disposal of materials at sites associated with past and present operations, including sites at which the company has been identified as a Potentially Responsible Party (PRP) under the federal Superfund laws and comparable state laws. Costs incurred at the California Utilities to operate the facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Significant costs incurred to mitigate or prevent future environmental contamination or extend the life, increase the capacity, or improve the safety or efficiency of property utilized in current operations are capitalized. The company's capital expenditures to comply with environmental laws and regulations were $14 million in 2003, $8 million in 2002 and $6 million in 2001. The cost of compliance with these regulations over the next five years is not expected to be significant.

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

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of the California Utilities' manufactured-gas sites (29 completed as of December 31, 2003 and 16 to be completed), cleanup at SDG&E's former fossil fuel power plants (all sold in 1999 and actual or estimated cleanup costs included in the transactions), cleanup of third-party waste-disposal sites used by the company, which has been identified as a PRP (investigations and remediations are continuing) and mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS (the requirements for enhanced fish protection, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands are in process).

Environmental liabilities are recorded when the company's liability is probable and the costs are reasonably estimable. In many cases, however, investigations are not yet at a stage where the company has been able to determine whether it is liable or, if the liability is probable, to reasonably estimate the amount or range of amounts of the cost or certain components thereof. Estimates of the company's liability are further subject to other uncertainties, such as the nature and extent of site contamination, evolving remediation standards and imprecise engineering evaluations. The accruals are reviewed periodically and, as investigations and remediation proceed, adjustments are made as necessary. At December 31, 2003, the company's accrued liability for environmental matters was $61.4 million, of which $48.7 million related to manufactured-gas sites, $10.5 million to cleanup at SDG&E's former fossil-fueled power plants, $2.1 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 accruals for the manufactured-gas and waste-disposal sites are expected to be paid ratably over the next three years. The accruals for SDG&E's former fossil-fueled power plants are expected to be paid ratably over the next two years.

Nuclear Insurance

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. The insurance policy provides $300 million in coverage, which is the maximum amount available. In addition to this primary financial protection, the Price-Anderson Act provides for up to $10.6 billion of secondary financial protection if the liability loss exceeds the insurance limit. Should any of the licensed/commercial reactors in the United States experience a nuclear liability loss which exceeds the $300 million insurance limit, all utilities owning nuclear reactors could be assessed under the Price-

Anderson Act to provide the secondary financial protection. SDG&E and the other co-owners of SONGS could be assessed up to $201 million under the Price-Anderson Act. SDG&E's share would be $40 million unless a default were to occur by any other SONGS co-owner. In the event the secondary financial protection limit were insufficient to cover the liability loss, the Price-Anderson Act provides for Congress to enact further revenue-raising measures to pay claims. These measures could include an additional assessment on all licensed reactor operators.

SDG&E and the other owners of SONGS have $2.75 billion of nuclear property, decontamination and debris removal insurance. The coverage also provides the SONGS owners up to $490 million for outage expenses/replacement power incurred because of accidental property damage. This coverage is limited to $3.5 million per week for the first 52 weeks, and $2.8 million per week for up to 110 additional weeks. There is a deductible waiting period of 12 weeks prior to receiving indemnity payments. The insurance is provided through a mutual insurance company owned by utilities with nuclear facilities. Under the policy's risk sharing arrangements, insured members are subject to retrospective premium assessments if losses at any covered facility exceed the insurance company's surplus and reinsurance funds. Should there be a retrospective premium call, SDG&E could be assessed up to $7.4 million.

Both the nuclear liability and property insurance programs include industry aggregate limits for terrorism-related SONGS losses, including replacement power costs.

Litigation

During 2003, the company recorded $49 million of after-tax charges related to litigation costs and a SoCalGas sublease. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations. Except for the matters referred to below, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

DWR Contract

In May 2003, the San Diego Superior Court granted SER's motion for summary judgment on its complaint regarding its contract with the DWR (and the DWR's cross-complaint seeking to void the 10-year energy-supply contract). The court determined that "(a) Sempra is entitled to provide electrical energy from any source, including Market Sources, (b) Sempra is not in breach of the Agreement as framed by the pleadings in this matter, (c) DWR is obligated to take delivery and pay for deliveries under the Agreement, and (d) Sempra has no obligation to complete any specific Project." The DWR filed a motion for a new trial claiming irregularities in the Court's judgment. The Court subsequently clarified its earlier summary judgment ruling and effectively denied the motion for new trial. An amended judgment was entered by the Court. The DWR has filed a notice of appeal on the judgments and the Court's clarification. A decision by the appellate court is expected sometime during 2005. The DWR continues to accept all scheduled power from SER and, although it has disputed billings in an immaterial amount and the manner of certain deliveries, it has paid all amounts that have been billed under the contract.

Antitrust Litigation

Class-action and individual lawsuits filed in 2000 and currently consolidated in San Diego Superior Court seek damages, alleging that Sempra Energy, SoCalGas and SDG&E, along with El Paso Energy Corp. (El Paso) and several of its affiliates, unlawfully sought to control natural gas and electricity markets. In March 2003, plaintiffs in these cases and the applicable El Paso entities announced that they had reached a $1.5 billion settlement, of which $125 million is allocated to customers of the California Utilities. The Court approved that settlement in December 2003. The proceeding against Sempra Energy and the California Utilities has not been settled and continues to be litigated.

Natural Gas Cases: Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada, alleging that El Paso and certain Sempra Energy subsidiaries unlawfully sought to control the natural gas market in their respective states. In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, including Sempra Energy, the California Utilities and other company subsidiaries, seeking damages resulting from an alleged conspiracy to drive up or control natural gas prices, eliminate competition and increase market volatility, breach of contract and wire fraud. On January 27, 2004, the U.S. District Court dismissed the Sierra Pacific Resources case against all of the defendants, determining that this is a matter for the FERC.

Electricity Cases: Various lawsuits, which seek class-action certification, allege that Sempra Energy and certain company subsidiaries (SDG&E, SET and SER, depending on the lawsuit) unlawfully manipulated the electric-energy market. In January 2003, the applicable federal court granted a motion to dismiss a similar lawsuit on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act. That ruling has been appealed in the Ninth Circuit Court of Appeals, which is expected to hear the appeal in the first quarter of 2004. Similar suits filed in Washington and Oregon were voluntarily dropped by the plaintiffs without court intervention in June 2003. In addition, in May 2003, the Port of Seattle filed an action alleging that a number of energy companies, including Sempra Energy, SER and SET, unlawfully manipulated the electric energy market and committed wire fraud. That action has been transferred to San Diego Federal District Court and is currently pending a motion to dismiss on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act.

SER, SET and SDG&E, along with all other sellers in the western power market, have been named defendants in a complaint filed at the FERC by the California Attorney General's office seeking refunds for electricity purchases based on alleged violations of FERC tariffs. The FERC has dismissed the complaint. The California Attorney General has filed an appeal in the 9th Circuit.

Price Reporting Practices

In the fourth quarter of 2002, Sempra Energy and SoCalGas were named as defendants in a lawsuit filed in Los Angeles Superior Court against various trade publications and other energy companies alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications. On July 8, 2003, the Superior Court granted the defendants' demurrer on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act. Plaintiffs filed an amended complaint, and in September 2003 defendants filed a demurrer to the amended complaint, which was granted in part. In December 2003, the plaintiffs dismissed both Sempra Energy and SoCalGas from the lawsuit. In May 2003 and again in February 2004, similar actions were filed in San Diego Superior Court against Sempra Energy and SET, and the May 2003 action has been removed to Federal District Court. Another lawsuit containing identical allegations was filed against Sempra Energy and SET in Federal District Court in November of 2003. In addition, in August 2003, a lawsuit was filed in the Southern District of New York against Sempra Energy and SES, alleging that the prices of natural gas options traded on the NYMEX were unlawfully increased under the Federal Commodity Exchange Act by defendants' manipulation of transaction data to natural gas trade publications. In November of 2003, another suit containing identical allegations was filed and consolidated with the New York action. In December 2003, plaintiffs dismissed Sempra Energy from these cases and in January 2004, SES was also dismissed. On January 20, 2004, plaintiffs filed an amended consolidated complaint that named SET as a defendant in this lawsuit.

In January 2004, the Commodity Futures Trading Commission (CFTC) issued a subpoena to SoCalGas and SET in connection with the CFTC's "Activities Affecting the Price of Natural Gas in the Fall of 2003" investigation. The company is cooperating with the CFTC in the investigation.

Other

On August 21, 2003, the CPUC denied a rehearing requested by opponents of its December 2002 decision that had approved a settlement with SDG&E allocating between SDG&E customers and shareholders the profits from intermediate-term purchase power contracts that SDG&E had entered into during the early stages of California's electric utility industry restructuring. As previously reported, the settlement provided $199 million of these profits to customers, by reductions to balancing account undercollections in prior years. The settlement provided the remaining $173 million of profits to SDG&E shareholders, of which $57 million had been recognized for financial reporting purposes in prior years. As a result of the decision, SDG&E recognized additional after-tax income of $65 million in the third quarter of 2003. UCAN, a consumer-advocacy group which had requested the CPUC rehearing, appealed the decision to the California Court of Appeals and the court agreed to hear the case. Oral arguments are likely to occur in March or April 2004. A decision is expected by the third quarter of 2004. The company expects that the Court of Appeals will affirm the CPUC's decision.

SER was a defendant in an action brought by Occidental Energy Ventures Corporation (Occidental) with respect to the Elk Hills power project being jointly developed by the two companies. On September 30, 2003, the arbitration proceeding found in favor of SER, determining that SER had not breached its joint development contract with Occidental.

In May 2003, a federal judge issued an order finding that the DOE's abbreviated assessment of two Mexicali power plants, including SER's TDM plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. In July 2003, the judge ordered the DOE to conduct additional environmental studies and denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE has until May 15, 2004, to demonstrate why the court should not set aside the permits.

In 1999, Sempra Energy and PSEG each acquired a 44-percent interest in Luz Del Sur, a Peruvian electric distribution company. Local law required that assets built with government funds be purchased by the local utility and added to rate base. A dispute arose between the government and Luz Del Sur over the amount of compensation due for the 194 projects transferred to Luz Del Sur by the government. The government claims the amount owed was $36 million. Luz Del Sur argued that the amount was less and the matter was settled with the government for approximately $10 million. Following a change in the Peruvian government, a criminal charge was filed against certain government officials, and utility officials as accomplices, including the chief executive officer and chief financial officer of Luz Del Sur, alleging that the settlements were inadequate. In September 2003 a Peruvian court ordered the prosecutor's case to be dismissed. Although the prosecutor has indicated no evidence of wrongdoing in the case, the prosecutor has appealed this decision and the case rests in a higher Peruvian court. A decision is expected during the first half of 2004.

At December 31, 2003, SET remains due approximately $100 million from energy sales made in 2000 and 2001 through the ISO and the PX markets. The collection of these receivables depends on satisfactory resolution of the financial difficulties being experienced by other California IOUs as a result of the California electric industry crisis. SET has submitted relevant claims in the PG&E and PX bankruptcy proceedings. The company believes adequate reserves have been recorded.

FERC Actions

Information regarding FERC actions related to the company is provided in Note 13.

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. This delay by the DOE will lead to increased cost for spent fuel storage. This cost will be recovered through SONGS revenue unless the company is able to recover the increased cost from the federal government.

Electric Distribution System Conversion

Under a CPUC-mandated program, the cost of which is included in utility rates, and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2003, the aggregate unexpended amount of this commitment was $90 million. Capital expenditures for underground conversions were $28 million in 2003, $33 million in 2002 and $12 million in 2001.

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 California Utilities grant credit to utility customers and counterparties, substantially all of whom are located in their service territories, which together cover most of Southern California and a portion of central California.

As described above, SER has a contract with the DWR to supply up to 1,900 MW of power to the state over 10 years, beginning in 2001. SER would be at risk for the amounts of outstanding billings and the continued viability of the contract if the DWR were to default on its payments under this contract. At any given time, the average outstanding billings related to this contract is $50 million to $60 million.

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

NOTE 16. SEGMENT INFORMATION

The company has four separately managed reportable segments comprised of SoCalGas, SDG&E, SET and SER. The California Utilities operate in essentially separate service territories under separate regulatory frameworks and rate structures set by the CPUC. SoCalGas is a natural gas distribution utility, serving customers throughout most of Southern California and part of central California. SDG&E provides electric service to San Diego and southern Orange counties and natural gas service to San Diego County. SET, based in Stamford, Connecticut, is a wholesale trader of physical and financial energy products and other commodities, and a trader and wholesaler of metals, serving a broad range of customers in the United States, Canada, Europe and Asia. SER acquires, develops and operates power plants throughout the U.S. and Mexico.

The accounting policies of the segments are described in Note 1, and segment performance is evaluated by management based on reported net income. California Utility transactions are based on rates set by the CPUC and FERC.

Years ended December 31, (Dollars in millions)	2003	2002	2001
OPERATING REVENUES			
Southern California Gas	$ 3,544	$ 2,858	$ 3,716
San Diego Gas & Electric	2,311	1,725	2,362
Sempra Energy Trading	1,144	821	1,047
Sempra Energy Resources	671	349	178
All other	274	332	458
Intersegment revenues	(57)	(37)	(31)
Total	$ 7,887	$ 6,048	$ 7,730
INTEREST INCOME			
Southern California Gas	$ 34	$ 5	$ 22
San Diego Gas & Electric	42	10	21
Sempra Energy Trading	12	11	11
Sempra Energy Resources	14	4	6
All other	132	84	73
Intercompany elimination	(130)	(72)	(50)
Total	$ 104	$ 42	$ 83
DEPRECIATION AND AMORTIZATION			
Southern California			

~~Gas $ 289 $ 276 $ 268 San Diego Gas & Electric 242 230 207 Sempra Energy Trading 23 21 27 Sempra Energy Resources 13 2 1 All other 48 67 76~~

~~Total $ 615 $ 596 $ 579~~

~~INTEREST EXPENSE Southern California Gas $ 45 $ 44 $ 68 San Diego Gas & Electric 73 77 92 Sempra Energy Trading 30 43 14 Sempra Energy Resources 25 6 7 All other 265 196 192 Intercompany elimination (130) (72) (50)~~

~~Total $ 308 $ 294 $ 323~~

~~INCOME TAX EXPENSE (BENEFIT) Southern California Gas $ 150 $ 178 $ 169 San Diego Gas & Electric 148 91 141 Sempra Energy Trading 62 60 131 Sempra Energy Resources 29 36 (18) All other (342) (219) (210)~~

~~Total $ 47 $ 146 $ 213~~

~~NET INCOME (LOSS) Southern California Gas $ 209 $ 212 $ 207 San Diego Gas & Electric 334 203 177 Sempra Energy~~

~~Trading 98 126 196 Sempra Energy Resources 94 60 (27) All other (86) (10) (35) ------~~

~~Total $ 649 $ 591 $ 518~~

~~127 At December 31 or years ended December 31,~~

~~(Dollars in millions) 2003 2002 2001~~

~~ASSETS Southern California Gas $ 5,412 $ 5,403 $ 4,986 San Diego Gas & Electric 6,463 6,285 6,542 Sempra Energy Trading 5,923 5,614 2,997 Sempra Energy Resources 2,252 1,347 577 All other 2,780 2,579 3,094 Intersegment receivables (821) (986) (720)~~

~~Total $ 22,009 $ 20,242 $ 17,476~~

~~CAPITAL EXPENDITURES Southern California Gas $ 318 $ 331 $ 294 San Diego Gas & Electric 444 400 307 Sempra Energy Trading 51 21 45 Sempra Energy Resources 142 356 225 All other~~

	~~94~~	~~106~~	~~197~~
~~Total~~	~~$ 1,049~~	~~$ 1,214~~	~~$ 1,068~~
~~GEOGRAPHIC INFORMATION~~			
~~Long-lived assets~~			
~~United States~~	~~$ 10,380~~	~~$ 9,548~~	~~$ 8,911~~
~~Latin America~~	~~1,121~~	~~1,062~~	~~836~~
~~Europe~~	~~87~~	~~18~~	~~10~~
~~Canada~~	~~—~~	~~3~~	~~24~~
~~Total~~	~~$ 11,588~~	~~$ 10,631~~	~~$ 9,781~~
~~Operating revenues~~			
~~United States~~	~~$ 7,211~~	~~$ 5,503~~	~~$ 7,169~~
~~Latin America~~	~~315~~	~~168~~	~~280~~
~~Europe~~	~~323~~	~~328~~	~~250~~
~~Canada~~	~~10~~	~~28~~	~~15~~
~~Asia~~	~~28~~	~~21~~	~~16~~
~~Total~~	~~$ 7,887~~	~~$ 6,048~~	~~$ 7,730~~

NOTE 17. QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarters ended (Dollars in millions, except per share amounts)	March 31	June 30	September 30	December 31
2003				
Operating revenues	$ 1,923	$ 1,840	$ 2,058	$ 2,066
Operating expenses	1,708	1,637	1,751	1,852
Operating income	$ 215	$ 203	$ 307	$ 214
Income before cumulative effect of changes in accounting principles	$ 117	$ 116	$ 211	$ 251
Net income	$ 88	$ 116	$ 211	$ 234
Average common shares outstanding (diluted)	207.8	210.2	212.3	227.2
Income per common share before cumulative effect of changes in accounting principles (diluted)	$ 0.56	$ 0.55	$ 1.00	$ 1.11
Net income per common share (diluted)	$ 0.42	$ 0.55	$ 1.00	$ 1.03
2002				
Operating revenues	$ 1,475	$ 1,488	$ 1,385	$ 1,700
Operating expenses	1,224	1,260	1,075	1,502
Operating income	$ 251	$ 228	$ 310	$ 198
Income before extraordinary item	$ 146	$ 145	$ 150	$ 134
Net				

~~income $ 146 $ 147 $ 150 $ 148 Average common shares outstanding (diluted) 206.4 207.1 205.4 205.6 Income per common share before extraordinary item (diluted) $ 0.71 $ 0.70 $ 0.73 $ 0.65 Net income per common share (diluted) $ 0.71 $ 0.71 $ 0.73 $ 0.72~~

~~Reclassifications have been made to certain of the amounts since they were presented in the Quarterly Reports on Form 10-Q.~~

QUARTERLY COMMON STOCK DATA (UNAUDITED)

First Quarter Second Quarter Third Quarter Fourth Quarter

~~2003 Market price High $26.00 $29.40 $30.33 $30.90 Low $22.25 $24.05 $27.31 $26.36~~

~~2002 Market price High $25.92 $26.25 $24.11~~

~~$24.62~~
~~Low~~
~~$22.15~~
~~$21.52~~
~~$15.50~~
~~$16.70~~

Dividends declared were $0.25 in each quarter.

FORM 10-K

Sempra Energy's annual report to the Securities and Exchange Commission
on Form 10-K is available to shareholders at no charge by writing to
Shareholder Services at 101 Ash Street, San Diego, CA 92101.

EXHIBIT 21.01

SEMPRA ENERGY
Schedule of Significant Subsidiaries at December 31, 2003

Subsidiary	State of Incorporation or Other Jurisdiction
Chilquinta Energia, S.A.	Chile
Luz del Sur, S.A.A.	Peru
San Diego Gas & Electric Company	California
Sempra Energy Financial	California
Sempra Energy Global Enterprises	California
Sempra Energy International	California
Sempra Energy Resources	California
Sempra Energy Solutions	California
Sempra Energy Trading Corp.	Delaware
Sempra Energy Trading International B.V.	The Netherlands
Sempra Metals Group Limited	United Kingdom
Sodigas Pampeana S.A.	Argentina
Sodigas Sur S.A.	Argentina
Southern California Gas Company	California

EXHIBIT 31.1

CERTIFICATION

I, Stephen L. Baum, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sempra Energy;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements and other financial information included in this Annual Report fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and we have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report, based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

February 24, 2004

/S/ STEPHEN L. BAUM
Stephen L. Baum
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Neal E. Schmale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sempra Energy;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements and other financial information included in this Annual Report fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and we have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report, based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

February 24, 2004

/S/ NEAL E. SCHMALE
Neal E. Schmale
Chief Financial Officer

Exhibit 32.1

Statement of Chief Executive Officer

Pursuant to 18 U.S.C. Sec 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned Chief Executive Officer of Sempra Energy (the "Company") certifies that:

(i) the Annual Report on Form 10-K of the Company filed with the Securities and Exchange Commission for the year ended December 31, 2003 (the "Annual Report") fully complies with the requirements of Section 13(a) or Section 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2004

/S/ STEPHEN L. BAUM

Stephen L. Baum
Chief Executive Officer

Exhibit 32.2

Statement of Chief Financial Officer

Pursuant to 18 U.S.C. Sec 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned Chief Financial Officer of Sempra Energy (the "Company") certifies that:

(i) the Annual Report on Form 10-K of the Company filed with the Securities and Exchange Commission for the year ended December 31, 2003 (the "Annual Report") fully complies with the requirements of Section 13(a) or Section 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2004

/S/ NEAL E. SCHMALE

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Neal E. Schmale
Chief Financial Officer