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

INTRODUCTION

This section of the 2004 Annual Report includes management's discussion and analysis of operating results from 2002 through 2004, and provides information about the capital resources, liquidity and financial performance of 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 Annual Report.

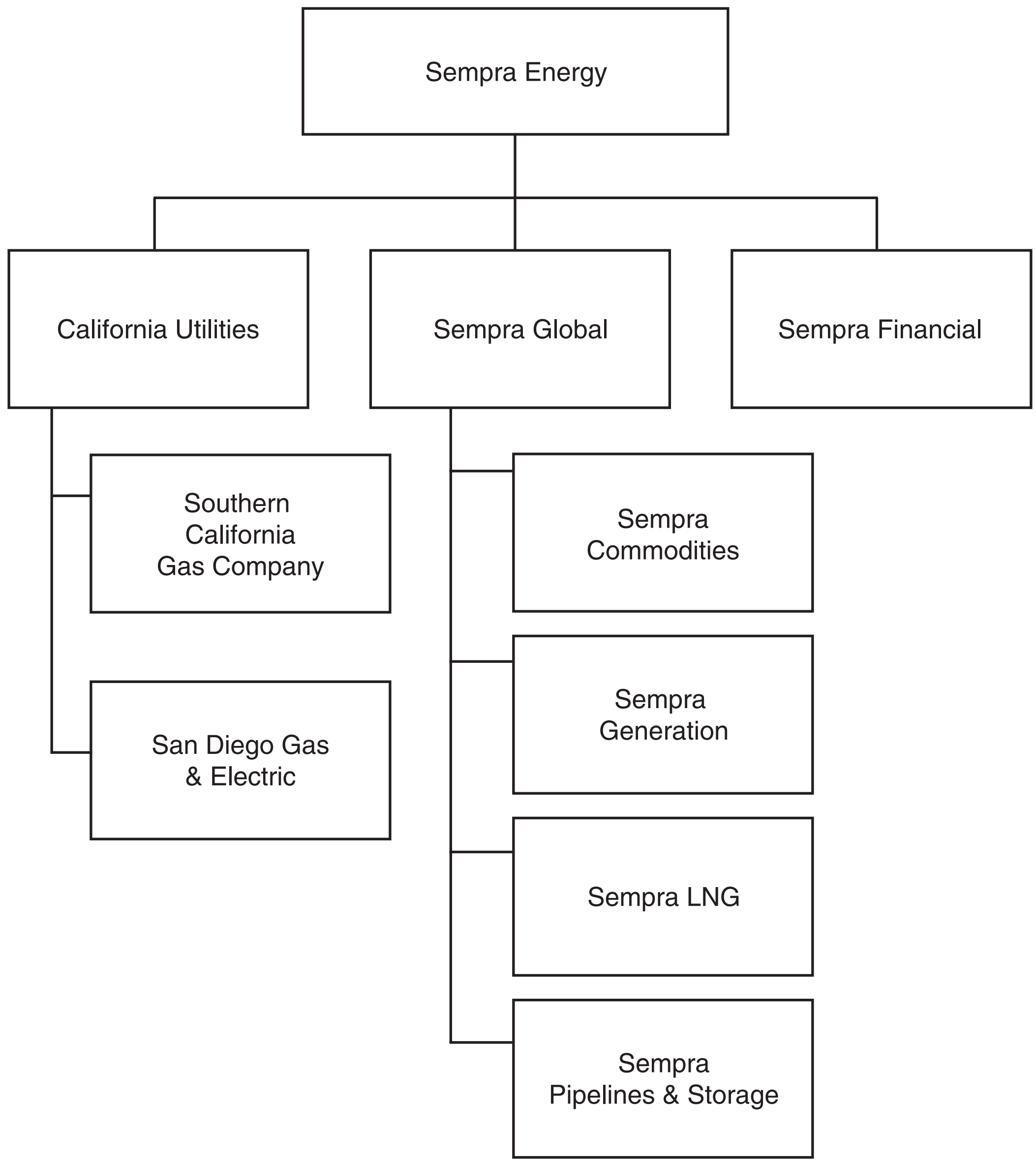
OVERVIEW

Sempra Energy

Sempra Energy is a Fortune 500 energy services holding company. Its business units provide a wide spectrum of value-added products and services to a diverse range of customers. On January 1, 2005, the names for some of the company's subsidiaries changed. Sempra Energy Global Enterprises is now Sempra Global. Sempra Energy Financial is now Sempra Financial. Sempra Energy Trading is now Sempra Commodities. Sempra Energy Resources is now Sempra Generation. Sempra Energy International is now Sempra Pipelines & Storage. Sempra Energy LNG is now Sempra LNG.

In addition, on December 1, 2004, Sempra Energy Solutions' commodities business was absorbed into Sempra Commodities, while its other businesses, energy services and facilities management, are now part of Sempra Generation. As a result, certain prior-year amounts have been revised to conform to the current year's presentation.

The company's operations are divided into delivery services (the California Utilities), Sempra Global and Sempra Financial, as described below.



Summary descriptions of the operating business units are provided below and further detail is provided throughout this section of the Annual Report.

Major events during 2004 affecting the results for the year and future years (and the page number where each is discussed) include the following:

- Continuing legal proceedings concerning anti-trust claims made against the company, San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas) (101) and concerning Sempra Generation's contract with the California Department of Water Resources (DWR) (101);
- Acquisition of the Coleto Creek Power Station and nine other Texas power plants by a 50% owned joint venture (60);
- Continued development of the liquefied natural gas (LNG) business (17);
- Significantly increased net income at Sempra Commodities due to market volatility and at Sempra Generation due to increased volumes under the DWR contract (8);
- Commencement of construction by the company's generation subsidiary of the Palomar power plant to be owned by SDG&E (14);
- California Public Utilities Commission (CPUC) cost of service decision in 2004 relating to the California Utilities' rates through 2007 (11);
- Final court decision in 2004 resolving the CPUC settlement relating to SDG&E's intermediate-term power-purchase contracts (7);
- Discontinuance of Atlantic Electric & Gas (AEG) operations (10); and
- Transfer of the company's retail energy-related product and service businesses to Sempra Commodities and Sempra Generation (1).

The California Utilities

SoCalGas and SDG&E (collectively, the California Utilities) serve 23 million consumers from California's Central Valley to the Mexican border. Natural gas service is provided throughout Southern California and portions of central California through 6.3 million meters. Electric service is provided throughout San Diego County and portions of Orange County, both in Southern California, through 1.3 million meters.

Sempra Global

Sempra Global is a holding company for most of the subsidiaries of Sempra Energy that are not subject to California utility regulation.

Sempra Global's principal subsidiaries provide the following energy-related products and services:

- Sempra Commodities is a wholesale and retail trader of physical and financial products, including natural gas, power, crude oil and other commodities; a trader and wholesaler of metals, serving a broad range of customers; and an owner of synthetic fuel facilities that generate Section 29 income tax credits;
- Sempra Generation acquires, develops and operates power plants, provides energy services and facilities management, and owns mineral rights in properties that produce petroleum and natural gas;
- Sempra LNG is developing receipt terminals for the importation of LNG and has an agreement to supply natural gas to Mexico's state-owned electric utility; and
- Sempra Pipelines & Storage engages in energy-infrastructure projects in North and South America. It holds interests in companies that provide natural gas or electricity services to over 2.8 million customers in Argentina, Chile, Mexico and Peru; develops natural gas pipelines and storage facilities; and owns two small natural gas distribution utilities in the eastern United States.

Sempra Financial

In order to reduce Sempra Energy's income taxes, Sempra Financial invests in tax-advantaged limited partnerships which own 1,300 affordable-housing properties throughout the United States.

RESULTS OF OPERATIONS

Overall Operations

Net income was $895 million in 2004, a 37.9% increase over 2003, and diluted earnings per share were $3.83, an increase of 26.4%, as described below. The percentage increase in diluted earnings per share was less than the percentage increase in earnings due to the issuance of shares in late 2003 to expand Sempra Global's businesses. The increase in net income was primarily due to increased profits at Sempra Commodities and Sempra Generation and the fact that 2003's results included a significant write-down in the Sempra Pipelines & Storage business unit.

The following table shows net income and diluted earnings per share for each of the last five years.

(Dollars in millions, except per share amounts)	Net Income	Diluted Earnings Per Share
2004	**$895**	**$3.83**
2003	$649	$3.03
2002	$591	$2.87
2001	$518	$2.52
2000	$429	$2.06

Net Income (Loss) by Business Unit

	Years ended December 31,					
(Dollars in millions)	**2004**		2003		2002	
California Utilities						
Southern California Gas Company	**$232**	**26%**	$ 209	32%	$212	36%
San Diego Gas & Electric	**208**	**23**	334	52	203	34
Total Utilities	**440**	**49**	543	84	415	70
Sempra Global						
Sempra Commodities	**320**	**36**	157	24	149	25
Sempra Generation	**137**	**15**	71	11	42	7
Sempra Pipelines & Storage	**63**	**7**	3	—	26	5
Sempra LNG	**(8)**	**(1)**	(2)	—	—	—
Total Sempra Global	**512**	**57**	229	35	217	37
Sempra Financial	**36**	**4**	41	6	36	6
Parent and other*	**(68)**	**(7)**	(118)	(18)	(93)	(16)
Continuing operations	**920**	**103**	695	107	575	97
Discontinued operations	**(25)**	**(3)**	—	—	—	—
Extraordinary item	**—**	**—**	—	—	16	3
Cumulative effect of changes in accounting principles	**—**	**—**	(46)	(7)	—	—
Consolidated net income	**$895**	**100%**	$ 649	100%	$591	100%

* Includes after-tax interest expense of $112 million, $100 million and $70 million in 2004, 2003 and 2002, respectively, intercompany eliminations recorded in consolidation and certain corporate costs incurred at Sempra Global.

Comparison of Earnings

To assist in understanding the trend of earnings the following table summarizes the major unusual factors affecting net income and operating income in 2004, 2003 and 2002. The numbers in parentheses are the page numbers where each item is discussed herein.

	Net Income			Operating Income		
(Dollars in millions)	**2004**	2003	2002	**2004**	2003	2002
Reported amounts	**$895**	$ 649	$591	**$1,272**	$ 939	$987
Unusual items:						
Discontinued operations — AEG (10)	**25**	—	—	**—**	—	—
AEG equity losses — disposed of in April 2004 (10)	**—**	5	10	**—**	—	—
Asset impairments of Frontier Energy (54) and AEG (54)	**—**	68	—	**—**	101	—
Gains on sale of SoCalGas' partnership property (10) and on partial sale of Luz del Sur (13)	**(14)**	—	—	**—**	—	—
Gain on settlement of Cameron liability (13)	**(8)**	—	—	**—**	—	—
Prior years' income tax issues (68)	**(56)**	(118)	(25)	**—**	—	—
California energy crisis litigation costs (101)	**84**	38	13	**140**	66	23
Regulatory issues (11)	**(55)**	—	—	**(51)**	—	—
SoCalGas' natural gas procurement awards (6)	**—**	(29)	—	**—**	(49)	—
SoCalGas sublease losses (9)	**—**	11	—	**—**	19	—
Resolution of vendor disputes in Argentina (13)	**(12)**	(11)	—	**—**	—	—
SDG&E power contract settlement (7)	**—**	(65)	—	**—**	(116)	—
SONGS incentive pricing (ended 12/31/03) (50)	**—**	(53)	(50)	**—**	(89)	(84)
Merger savings (91)	**—**	—	(25)	**—**	—	(42)
Changes in accounting principles:						
Repeal of EITF 98-10 (54)	**—**	29	—	**—**	—	—
Adoption of FIN 46 (30)	**—**	17	—	**—**	—	—
Impact of the repeal of EITF 98-10 (54)	**—**	(9)	—	**—**	(15)	—
Extraordinary item (48)	**—**	—	(16)	**—**	—	—
	$859	$ 532	$498	**$1,361**	$ 856	$884

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 national, state and local levels. The primary regulatory body is the CPUC, which regulates utility rates and operations. The Federal Energy Regulatory Commission (FERC) regulates interstate transportation of natural gas and electricity and various related matters. The Nuclear Regulatory Commission regulates nuclear generating plants. Municipalities and other local authorities regulate the location of utility assets, including natural gas pipelines and electric lines. Other business units are also subject to regulation by the FERC, various state commissions, local governmental entities, and various similar authorities 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.

In 2003, the CPUC established the allocation of the power purchased by the DWR under long-term contracts for the IOUs' customers and the related cost responsibility among the IOUs for that power. In addition, the IOU's resumed their electric commodity procurement function for power requirements in excess of that provided by the DWR's contracts allocated to them. This is discussed further in Note 14 of the notes to Consolidated Financial Statements and under "Factors Influencing Future Performance."

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. Further restructuring continues to be considered, as discussed in Note 15 of the notes to Consolidated Financial Statements.

Natural Gas Revenue and Cost of Natural Gas. Natural gas revenues increased to $4.5 billion in 2004 from $4.0 billion in 2003, and the cost of natural gas increased to $2.6 billion in 2004 from $2.1 billion in 2003. The increases were primarily attributable to natural gas cost increases, which are passed on to customers. For natural gas revenues, this increase was offset by $56 million of approved performance awards recognized during 2003, including $49 million of natural gas procurement awards at SoCalGas. Performance awards are discussed in Note 15 of the notes to Consolidated Financial Statements. The company's weighted average cost per million British thermal units (mmbtu) of natural gas was $5.94 in 2004, $5.06 in 2003 and $3.12 in 2002.

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 market-based 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. Further discussion is provided in Notes 1 and 15 of the notes to Consolidated Financial Statements.

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. The change was primarily attributable to natural gas price increases, offset by reduced volumes. Revenues also increased due to the performance awards recognized during 2003.

Electric Revenue and Cost of Electric Fuel and Purchased Power. Electric revenues decreased to $1,658 million in 2004 from $1,787 million in 2003, and the cost of electric fuel and purchased power increased to $0.6 billion in 2004 from $0.5 billion in 2003. The decrease in revenues was due to more power being provided to SDG&E's customers by the DWR in 2004 as discussed in Note 14 of the notes to Consolidated Financial Statements, offset by higher electric commodity costs. Additionally, 2003 revenue included the recognition of $116 million related to the approved settlement of intermediate-term purchase power contracts in the third quarter of 2003 and higher earnings from PBR awards. Performance awards are discussed in Note 15 of the notes to Consolidated Financial Statements. The increased costs were primarily attributable to the higher electric commodity costs and higher volumes, offset by the increased power being provided by the DWR.

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

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

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
2004:						
Residential	**287**	**$2,904**	**2**	**$ 7**	**289**	**$2,911**
Commercial and industrial	**126**	**1,013**	**276**	**198**	**402**	**1,211**
Electric generation plants	**—**	**2**	**252**	**90**	**252**	**92**
Wholesale	**—**	**—**	**20**	**6**	**20**	**6**
	413	**$3,919**	**550**	**$301**	**963**	**4,220**
Balancing accounts and other						**317**
Total						**$4,537**
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

ELECTRIC TRANSMISSION AND DISTRIBUTION
(Dollars in millions, volumes in million kilowatt hours)

	2004		2003		2002	
	Volumes	**Revenue**	Volumes	Revenue	Volumes	Revenue
Residential	**7,038**	**$ 692**	6,702	$ 731	6,266	$ 649
Commercial	**6,592**	**644**	6,263	674	6,053	633
Industrial	**2,072**	**133**	1,976	161	1,883	160
Direct access	**3,441**	**105**	3,322	87	3,448	117
Street and highway lighting	**97**	**11**	91	11	88	9
Off-system sales	**—**	**—**	8	—	5	—
	19,240	**1,585**	18,362	1,664	17,743	1,568
Balancing accounts and other		**73**		123		(286)
Total		**$1,658**		$1,787		$1,282

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

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)	**2004**		2003		2002	
OPERATING REVENUES						
Sempra Commodities	**$1,680**	**52%**	$1,217	58%	$ 910	60%
Sempra Generation*	**1,647**	**51**	773	37	437	29
Sempra Pipelines & Storage*	**269**	**9**	210	10	176	12
Sempra LNG	**—**	**—**	(2)	—	—	—
Total Sempra Global	**3,596**	**112**	2,198	105	1,523	101
Parent and Other**	**(381)**	**(12)**	(108)	(5)	(20)	(1)
Total	**$3,215**	**100%**	$2,090	100%	$1,503	100%
COST OF SALES						
Sempra Commodities	**$ 597**	**34%**	$ 542	45%	$ 293	41%
Sempra Generation	**1,198**	**69**	498	41	274	39
Sempra Pipelines & Storage	**209**	**12**	166	14	148	21
Total Sempra Global	**2,004**	**115**	1,206	100	715	101
Parent and Other**	**(263)**	**(15)**	(2)	—	(6)	(1)
Total	**$1,741**	**100%**	$1,204	100%	$ 709	100%

* Does not include the revenues of the unconsolidated affiliates that are part of this business unit.
** Includes intercompany eliminations recorded in consolidation, including the Palomar plant in 2004 as discussed in Note 2 of the notes to Consolidated Financial Statements.

The increase in 2004 revenues compared to 2003 was primarily due to higher revenues at Sempra Generation resulting from increased volumes of power sales under the DWR contract, and higher revenues at Sempra Commodities resulting from increased commodity revenue, particularly from metals, natural gas and petroleum due to increased volatility and higher prices. The increase in cost of sales was primarily due to costs related to the higher sales volume for Sempra Generation.

The increases in 2003 compared to 2002 were primarily due to higher revenues at Sempra Commodities as the result of increased volumes and volatility in the energy commodity markets, as well as increased revenues from Sempra Generation'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.

Other Operating Expenses. This table provides a breakdown of other operating expenses by business unit.

(Dollars in millions)	**2004**		2003		2002	
OTHER OPERATING EXPENSES						
California Utilities						
Southern California Gas Company	**$ 950**	**40%**	$ 954	42%	$ 872	46%
San Diego Gas & Electric	**593**	**25**	637	28	560	29
Total Utilities	**1,543**	**65**	1,591	70	1,432	75
Sempra Global						
Sempra Commodities	**564**	**24**	409	18	338	18
Sempra Generation	**150**	**6**	132	6	78	4
Sempra Pipelines & Storage	**43**	**2**	120	5	49	3
Sempra LNG	**26**	**1**	1	—	—	—
Total Sempra Global	**783**	**33**	662	29	465	25
Parent and Other*	**45**	**2**	34	1	4	—
Total	**$2,371**	**100%**	$2,287	100%	$1,901	100%

* Includes certain intercompany eliminations recorded in consolidation.

The increase in other operating expenses in 2004 was primarily the result of higher costs at Sempra Global, particularly at Sempra Commodities due to increased trading activity, start-up costs at Sempra LNG and higher costs at Sempra Generation due to new generating plants coming on line in 2003. Additionally, 2004 operating expenses include higher litigation costs. These increases were offset by a decrease at the California Utilities in 2004, primarily resulting from the favorable resolution of regulatory issues in 2004 and a $75 million before-tax charge in 2003 for litigation costs and for losses associated with a sublease of portions of the SoCalGas headquarters building. Additionally, 2003 operating expenses at Sempra Pipelines & Storage include a $77 million before-tax write-down of the carrying value of the assets of Frontier Energy, and operating costs in 2003 were affected by a $24 million before-tax write-down of the carrying value of the assets of AEG, included in Parent and Other.

The increase in other operating expenses at the California Utilities in 2003 from 2002 was primarily the result of the charge for litigation costs and for losses associated with a sublease of portions of the SoCalGas headquarters building, and increased labor and employee benefits costs. A smaller portion of the increase was due to the California wildfires discussed in Note 15 of the notes to Consolidated Financial Statements, which primarily affected SDG&E and the costs of which are expected to be recovered in rates. General operating costs increased at Sempra Commodities due to the increased revenue activity and a full year's activities for the businesses acquired in 2002, at Sempra Generation due to the new power plants and at Sempra Pipelines & Storage due to the write-down of the carrying value of the assets of Frontier Energy. In addition, 2003 was impacted by the write-down of the carrying value of the assets of AEG and higher antitrust litigation costs at the Sempra Global companies.

Other Income. Other income, primarily equity earnings from unconsolidated subsidiaries and interest on regulatory balancing accounts, was $104 million, $26 million and $15 million in 2004, 2003 and 2002, respectively. The increase in 2004 compared to 2003 was due to lower equity losses at Sempra Financial, increased equity earnings at Sempra Generation resulting from the acquisition of the Coleto

Creek coal plant, the $15 million before-tax gain at SoCalGas from the sale of partnership property, the $13 million before-tax gain on the settlement of an unpaid portion of the purchase price of the proposed Cameron LNG project for an amount less than the liability (which had been recorded as a derivative) and a $7 million before-tax gain at Sempra Pipelines & Storage from the partial sale of Luz del Sur in 2004.

The increase for the 2003 year compared to 2002 was due to increased equity earnings at Sempra Pipelines & Storage and at other subsidiaries, and reduced balancing account interest expense, offset by higher 2002 operating results at Sempra Generation's joint ventures resulting from business interruption insurance proceeds received in 2002 related to an outage at the El Dorado plant during 2001.

Interest Income. Interest income was $69 million, $104 million and $42 million in 2004, 2003 and 2002, respectively. The decrease in 2004 was due to $59 million recorded as a result of the favorable resolution of income-tax issues with the Internal Revenue Service (IRS) in 2003, offset by interest recorded on income tax receivables in 2004. Additionally, the increase for 2003 compared to 2002 was due to the resolution of income tax issues in 2003.

Interest Expense. Interest expense was relatively unchanged at $322 million, $308 million and $294 million in 2004, 2003 and 2002, respectively.

Income Taxes. Income tax expense was $193 million, $47 million and $146 million in 2004, 2003 and 2002, respectively. The effective income tax rates were 17.3 percent, 6.3 percent and 20.2 percent, respectively. The change in income tax expense in 2004 was due primarily to higher taxable income and a $9 million decrease in income tax credits from synthetic fuel investments, which are discussed in Note 8 of the notes to Consolidated Financial Statements. Additionally, 2003 was impacted by the favorable resolution of income-tax issues, which reduced income tax expense by $83 million. 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 changes in 2003 from 2002 were due primarily to the favorable resolution of income tax issues and a $39 million increase in income tax credits from synthetic fuel investments, offset by a $25 million favorable resolution of income tax issues at SDG&E in 2002.

Discontinued Operations. In the first quarter of 2004, Sempra Energy's board of directors approved management's plan to dispose of the company's interest in AEG, which marketed power and natural gas commodities to commercial and residential customers in the United Kingdom. Including the $2 million loss on disposal, AEG's losses were $25 million for the year ended December 31, 2004. Note 4 of the notes to Consolidated Financial Statements provides further details.

During 2003 and 2002, the company accounted for its investment in AEG under the equity method of accounting. As such, for the years ended December 31, 2003 and 2002, the company recorded its share of AEG's net losses, $5 million and $10 million, respectively, in Other Income, Net on the Statements of Consolidated Income. Effective December 31, 2003, AEG was consolidated as a result of the adoption of Financial Accounting Standards Board (FASB) Financial Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities,* as discussed in Note 1 of the notes to Consolidated Financial Statements.

Net Income. Changes in net income are summarized in the table shown previously under "Comparison of Earnings".

Net Income by Business Unit

California Utilities

The net income of the California Utilities was adversely affected by $35 million in 2004 and $32 million in 2003 of after-tax litigation costs, and favorably affected by $55 million after tax in 2004 by the resolution of various regulatory issues as a result of the final decision on their 2004 cost of service proceedings. The litigation costs are primarily related to matters arising from the California energy crisis of 2000 — 2001. Resolution of the cost of service favorably impacted pension and other postretirement costs, income taxes and other matters in comparison to the assumptions used prior to January 1, 2004.

Southern California Gas Company

SoCalGas recorded net income of $232 million, $209 million and $212 million in 2004, 2003 and 2002, respectively. In addition to the matters noted above, the increase in 2004 was due to higher margins and the gain on the sale of partnership property. Additionally, 2003 net income was also affected by losses associated with a long-term sublease of portions of its headquarters building, offset by the favorable resolution of income tax issues and by higher GCIM awards.

The decrease for 2003 compared to 2002 was due primarily to the litigation charges and sublease losses in 2003 and the end of sharing of merger savings (which favorably impacted earnings by $17 million for the year ended December 31, 2002), offset by the resolution of income tax issues and higher GCIM awards in 2003.

San Diego Gas & Electric

SDG&E recorded net income of $208 million, $334 million and $203 million, in 2004, 2003 and 2002, respectively. In addition to the matters noted above, the decrease in 2004 was primarily due to the favorable resolution of income tax issues in 2003, which positively affected 2003 earnings by $79 million, income of $65 million after-tax in 2003 related to the approved settlement of intermediate-term purchase power contracts (discussed in Note 14 of the notes to Consolidated Financial Statements); the 2003 Incremental Cost Incentive Pricing income for the San Onofre Nuclear Generation Station (SONGS) and higher performance awards in 2003, offset by higher electric transmission and distribution margin in 2004.

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

Sempra Commodities

A summary of Sempra Commodities' trading margin by geographic region and product line follows:

Trading Margin (Dollars in millions)	**2004**		2003		2002	
Geographical:						
North America	**$ 689**	**67%**	$439	72%	$400	71%
Europe and Asia	**338**	**33**	172	28	165	29
Total	**$1,027**	**100%**	$611	100%	$565	100%
Product Line:						
Gas	**$ 314**	**31%**	$146	24%	$170	30%
Power	**166**	**16**	137	22	191	34
Oil — crude and products	**265**	**26**	128	21	74	13
Metals	**179**	**17**	96	16	78	14
Other	**103**	**10**	104	17	52	9
Total	**$1,027**	**100%**	$611	100%	$565	100%

Trading margin consists of net trading revenues less related costs (primarily brokerage, transportation and storage) plus or minus net interest income/expense.

The above amounts include the before-tax impact of its synthetic fuel credits of $79 million, $61 million and $28 million in 2004, 2003 and 2002, respectively, which contributed $29 million, $23 million and $11 million to net income in 2004, 2003 and 2002, respectively. Synthetic fuel credits are discussed in Note 8 of the notes to Consolidated Financial Statements.

Sempra Commodities recorded net income of $320 million in 2004 compared to $157 million in 2003 and $149 million in 2002, excluding the negative impact of the cumulative effect of the change in accounting principle of $29 million in 2003 and the extraordinary gain of $16 million in 2002. The increase in 2004 was primarily attributable to higher trading margins, resulting from increased volatility of a trending nature in the markets, particularly for metals, natural gas and petroleum.

A summary of Sempra Commodities' net unrealized revenues for trading activities follows:

	Years ended December 31,	
(Dollars in millions)	**2004**	2003
Balance at beginning of year	**$ 347**	$ 270
Cumulative effect adjustment	**—**	(50)
Additions	**1,606**	830
Realized	**(760)**	(703)
Balance at end of year	**$1,193**	$ 347

The estimated fair values for Sempra Commodities' net unrealized trading assets as of December 31, 2004, 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, 2004	Scheduled Maturity (in months) 0-12	13-24	25-36	>36
Prices actively quoted	$ 844	$ 788	$12	$10	$ 34
Prices provided by other external sources	23	(14)	—	—	37
Prices based on models and other valuation methods	(21)	(20)	—	—	(1)
Over-the-counter (OTC) revenue*	846	754	12	10	70
Exchange contracts**	347	337	21	8	(19)
Total	$1,193	$1,091	$33	$18	$ 51

* The present value of net unrealized revenues to be received from outstanding OTC contracts.

** Cash received associated with open Exchange contracts.

Sempra Generation

Sempra Generation recorded net income of $137 million in 2004; $71 million in 2003, excluding the favorable impact of the cumulative effect of the change in accounting principle of $9 million; and $42 million in 2002. The 2004 net income reflects a $7 million loss at the portions of Sempra Energy Solutions that were reorganized into Sempra Generation at the end of 2004, as described in the "Introduction" to this section. The change in accounting principle is discussed further in Note 1 of the notes to Consolidated Financial Statements. The increase in 2004 was primarily because power sales under Generation's contract with the DWR were at lower levels in 2003 and prior years than in 2004 and future years. The increase in 2003 compared to 2002 was primarily due to higher volumes of power sales to the DWR, offset by increased interest expense and start-up expenses related to Sempra Generation's new power plants.

Sempra Pipelines & Storage

Net income for Sempra Pipelines & Storage was $63 million, $3 million and $26 million for 2004, 2003 and 2002, respectively. 2003 net income was impacted by the charge recorded to write down the carrying value of assets at Frontier Energy, as previously discussed. Additionally, the increase for 2004 was due to higher earnings from the company's Gasoducto Bajanorte natural gas pipeline and a gain on the sale of a portion of its interests in Luz del Sur, a Peruvian electric utility, offset by the impact of changes in estimates for certain income tax issues. Both 2004 and 2003 were favorably impacted by the resolution of vendor disputes in Argentina.

The change in 2003 from 2002 was primarily due to the Frontier Energy impairment, offset by increased equity earnings from its South American joint ventures, a full year of earnings from the Gasaducto Bajanorte pipeline in Mexico, which began operations in September 2002, and the favorable resolution of vendor disputes in Argentina. A discussion of the Argentine economic issue is included in Notes 1 and 3 of the notes to Consolidated Financial Statements.

Sempra LNG

Sempra LNG recorded net losses of $8 million and $2 million, respectively, for the years ended December 31, 2004 and 2003. For 2004, operating costs were offset by income from the settlement of an unpaid portion of the purchase price of the proposed Cameron liquefied natural gas project for an amount less than the liability (which had been recorded as a derivative).

Sempra Financial

Sempra Financial recorded net income of $36 million in 2004, $41 million in 2003 and $36 million in 2002. During the third quarter of 2004, Sempra Financial sold its alternative fuel investment, Carbontronics. The transaction has been accounted for under the cost recovery method, whereby future proceeds in excess of Carbontronics' carrying value will be recorded as income as received. As a result of this sale, Sempra Financial will not be recognizing Section 29 income tax credits in the future.

The change in 2004 net income was due primarily to a decrease in tax credits, primarily due to the sale of Carbontronics, offset by lower equity losses. The increase in 2003 was due to lower amortization expense, offset by increased equity losses from certain investments.

Section 29 income tax credits are discussed further in Note 8 of the notes to Consolidated Financial Statements. Whether Sempra Financial 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 $68 million, $118 million and $93 million in 2004, 2003 and 2002, respectively. Net losses consist primarily of interest expense and, for 2004, include the $27 million after-tax impact of litigation costs, offset by a reduced estimate of federal and state income tax liabilities for certain prior years. Additionally, 2003 losses include the $21 million after-tax write down of the carrying value of the assets of AEG in 2003.

The increase in 2003 losses compared to 2002 was due to the 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 April 2002 and early 2003. The adoption of FIN 46 and the resulting consolidation of AEG is discussed in Note 1 of the notes to Consolidated Financial Statements.

Book Value Per Share

Book value per share was $20.77, $17.17 and $13.79, at December 31, 2004, 2003 and 2002, respectively. The increases in 2004 and 2003 were primarily the result of comprehensive income's exceeding the dividends, and the sale of additional shares of common stock for a per-share price in excess of its book value.

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, which are expected to provide significant cash flow in 2005, and on Sempra Commodities' liquidity requirements, which can fluctuate significantly.

At December 31, 2004, the company had $419 million in unrestricted cash and $4.5 billion in available unused, committed lines of credit to provide liquidity and support commercial paper. At December 31, 2004, $34 million of these lines supported variable-rate debt.

Management believes that these amounts and cash flows from operations and debt issuances will be adequate to finance capital expenditures and meet liquidity requirements and fund shareholder dividends, any new business acquisitions or start-ups, and other commitments. Forecasted capital expenditures for the next five years are discussed in "Future Construction Expenditures and Investments." 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, trading operations 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. Rating agencies and others that evaluate a company's liquidity generally consider a company's capital expenditures and working capital requirements in comparison to cash from operations, available credit lines and other sources available to meet liquidity requirements.

At the California Utilities, cash flows from operations and from security issuances are expected to continue to be adequate to meet utility capital expenditure requirements and provide dividends to Sempra Energy. In June 2004, SDG&E received CPUC approval of its intended 2006 purchase from Sempra Generation of the 550-megawatt (MW) Palomar generating facility being constructed in Escondido, California. As a result, 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. Note 2 of the notes to Consolidated Financial Statements provides additional discussion on the Palomar plant.

Sempra Commodities 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, including the credit line described below in “Cash Flows From Financing Activities.” Sempra Commodities’ intercompany borrowings were $421 million at December 31, 2004, and $359 million at December 31, 2003. Sempra Commodities’ external debt was $161 million at December 31, 2004. It had no external debt outstanding at December 31, 2003. Company management continuously monitors the level of Sempra Commodities’ cash requirements in light of the company’s overall liquidity. Such monitoring includes the procedures discussed in “Market Risk.”

Sempra Generation’s completed projects were financed through a combination of project financing, funds from the company and external borrowings. Existing and future projects are expected to be financed from Sempra Generation’s cash from operations, project financing and funds from the company.

Sempra Generation’s energy contracts typically contain collateral requirements related to credit lines. The collateral arrangements provide for Sempra Generation and/or the counterparty to post cash, guarantees or letters of credit to the other party for exposure in excess of established thresholds. Sempra Generation may be required to provide collateral when market price movements adversely affect the counterparty’s cost of replacement energy supplies were Sempra Generation to fail to deliver the contracted amounts. As of December 31, 2004, Sempra Generation had outstanding collateral requirements under these contracts of $139 million, of which $81 million had been remitted.

Sempra Pipelines & Storage 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 and storage to serve LNG facilities expected to be developed in Baja California, Mexico; Louisiana and Texas, as discussed in Note 2 of the notes to Consolidated Financial Statements.

Sempra LNG will require funding for its planned development of LNG receiving facilities. While Sempra LNG’s $1.25 billion credit facility is expected to be adequate for these requirements, the company may decide to use project financing if that is believed to be advantageous.

In the longer term, Sempra Financial is expected to again be a net provider of cash through reductions of consolidated income tax payments resulting from its investments in affordable housing. However, that was not true in 2003 and 2004, 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 $949 million, $1.1 billion and $1.4 billion for 2004, 2003 and 2002, respectively.

The 2004 decrease in net cash provided by operating activities was due to an increase in net trading assets in 2004 compared to a decrease in 2003, increased deposits with customers and a higher increase in accounts receivable in 2004, offset by an increase in overcollected regulatory balancing accounts at SoCalGas in 2004 compared to a decrease in 2003, higher net income and higher accounts payable in 2004.

The decrease in cash flows from operations in 2003 compared to 2002 was primarily attributable to changes in regulatory balancing accounts at the California Utilities, offset by higher accounts payable in 2003 primarily due to timing.

During 2004, the company made pension plan and other postretirement benefit plan contributions of $27 million and $50 million, respectively.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $559 million, $1.2 billion and $1.7 billion for 2004, 2003 and 2002, respectively.

The decrease in cash used in investing activities between 2004 and 2003 was primarily attributable to proceeds from the sale of U.S. Treasury obligations that previously securitized the Mesquite synthetic lease. The collateral was no longer necessary, since Sempra Generation bought out the lease in January 2004. The decrease in cash used in investing activities was also due to lower investments in Elk Hills (completed in 2003) and reduced capital spending for the completed Termoeléctrica de Mexicali (TDM) and Mesquite power plants, offset by investments made in Topaz Power Partners (Topaz) in 2004. In addition, the company received proceeds of $157 million from the disposal of AEG's discontinued operations.

The decrease in cash used in investing activities in 2003 compared to 2002 was primarily due to lower capital expenditures for the TDM and Twin Oaks power plants, lower investments in U.S. Treasury obligations made in connection with the Mesquite synthetic lease, higher distributions from investments in South America, and Sempra Commodities' acquisition activities in 2002.

Expenditures for property, plant and equipment, and for those investments that effectively constitute similar expenditures, are presented in the following table.

(Dollars in millions)	
2004	**$1,157**
2003	$1,228
2002	$1,524
2001	$1,179
2000	$ 963

The 2002 amount is larger than the other years due to the construction of the Sempra Generation power plants.

Capital Expenditures for Property, Plant and Equipment

Capital expenditures were $1.1 billion in 2004 compared with $1.0 billion in 2003 and $1.2 billion in 2002. The decrease in 2003 from 2002 was due primarily to lower capital expenditures for the TDM and Twin Oaks power plants.

The California Utilities

Capital expenditures for property, plant, and equipment by the California Utilities were $725 million in 2004 compared to $762 million in 2003 and $731 million in 2002. The higher amount in 2003 was primarily attributable to $40 million of capital costs associated with the Southern California wildfires in October 2003.

Sempra Generation

Sempra Generation is primarily in the business of acquiring, developing and operating power plants throughout the U.S. and Mexico. The following table lists the MW capacity of each operating power plant. All of the plants are natural gas-fired facilities, except for Coleto Creek Power and Twin Oaks Power, which are coal-fired, and a small hydroelectric plant.

Power Plant	Maximum Generating Capacity (MW)	Location
Pacific Southwest:		
Mesquite Power	1,250	Arlington, AZ
Termoeléctrica de Mexicali (TDM)	625	Mexicali, Baja California, Mexico
Elk Hills Power (50% owned)	275*	Bakersfield, CA
El Dorado (50% owned)	240*	Boulder City, NV
	2,390	
Texas:		
Coleto Creek Power (50% owned)	316*	Goliad County, TX
Twin Oaks Power	305	Bremond, TX
Five other active Topaz Power Partners power plants (50% owned)	659*	South Central, TX
	1,280	
Total MW in operation	3,670	

* Sempra Generation's share

Additional information concerning Sempra Generation's facilities is provided in Notes 2, 3 and 16 of the notes to Consolidated Financial Statements.

Sempra LNG

Sempra LNG develops, builds and operates LNG receipt terminals. Information concerning its projects in Baja California, Mexico; Louisiana and Texas is provided in Note 2 of the notes to Consolidated Financial Statements. The following additional matters are in process at the present time:

In January 2005, Sempra LNG signed a Heads of Agreement that will provide Tractebel LNG North America LLC with up to one-third (between 325 and 500 million cubic feet per day) of the processing capacity of the Cameron LNG facility. The non-binding agreement contemplates finalizing a definitive 20-year capacity agreement in 2005.

In January 2005, Sempra LNG was awarded a 15-year natural gas supply contract for 130 million cubic feet per day beginning in 2008. The contract supports Mexico's state-owned electric utility's future energy needs in northern Baja California and it is anticipated that it will use natural gas processed at Energía Costa Azul.

In December 2004, Sempra LNG entered into a non-binding development agreement with Alaska Gasline Port Authority to jointly consider and analyze the feasibility of building a proposed 800-mile gas pipeline from Alaska's North Slope to Valdez, where a gas liquefaction facility could be developed to export LNG to the western United States. The All-Alaska Gas Pipeline Project could be ready to deliver LNG to the West Coast receipt facilities as early as 2011. Whether the project will proceed and, if so, the ultimate extent of the company's participation are not determinable at this time.

Sempra Pipelines & Storage

Note 2 of the notes to Consolidated Financial Statements provides information concerning expenditures by Sempra Pipelines & Storage for its natural gas distribution systems in Mexico and its natural gas pipelines and storage facilities.

Sempra Commodities

Note 2 of the notes to Consolidated Financial Statements provides discussion of Sempra Commodities' expenditures for its Bluewater natural gas storage facility.

Investments

Investments and acquisition costs were $74 million, $202 million and $429 million for 2004, 2003 and 2002, respectively. The decrease in 2004 was due to the sale of U.S. Treasury obligations purchased in connection with the Mesquite synthetic lease and lower investments in Elk Hills, offset by investments made in Topaz in 2004. The decrease in 2003 was due to lower investments in U.S. Treasury obligations made in connection with the Mesquite synthetic lease in 2003 compared to 2002 and Sempra Commodities' acquisition activities in 2002. A discussion of the synthetic lease is provided in Note 2 of the notes to Consolidated Financial Statements.

Sempra Generation

Information concerning Sempra Generation's investments in Topaz, and the El Dorado and Elk Hills power plants is provided in Note 3 of the notes to Consolidated Financial Statements. In February 2005, Sempra Generation announced its intention to add 600 MW of capacity to its Twin Oaks coal-fired generating plant in Texas.

Sempra Pipelines & Storage

Discussion of investing activities by Sempra Pipelines & Storage, including the $198 million cumulative foreign currency exchange adjustment relating to Argentina, is provided in Note 3 of the notes to Consolidated Financial Statements.

Future Construction Expenditures and Investments

The company expects to make capital expenditures of $1.6 billion in 2005. Significant capital expenditures are expected to include $900 million for California utility plant improvements, $150 million for Palomar (discussed in Note 2 of the notes to Consolidated Financial Statements) and $300 million for the development of LNG regasification terminals. These expenditures are expected to be financed by cash flows from operations and debt issuances.

Over the next five years, the company expects to make capital expenditures of $5 billion at the California Utilities, and has identified $3.3 billion of capital expenditures at the other subsidiaries, including the development of the LNG facilities and pipelines, and construction of power plants by Sempra Generation. The former amount includes $500 million for Palomar, which is being constructed by Sempra Generation and which will be purchased by SDG&E when completed in 2006.

Construction, investment and financing programs are periodically reviewed and revised by the company in response to changes in regulation, economic conditions, competition, customer growth, inflation, customer rates, the cost of capital and environmental requirements as discussed in Note 16 of the notes to Consolidated Financial Statements. 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 (used in) provided by financing activities totaled $(380) million, $89 million and $137 million for 2004, 2003 and 2002, respectively.

The 2004 increase in cash used in financing activities was due to higher payments on long-term debt and lower issuances of common stock, offset by an increase in short-term debt. 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, offset by an increase in stock issuances.

Long-Term and Short-Term Debt

During 2004, the company's long-term debt decreased $684 million to $4.6 billion. At December 31, 2004, the company's long-term debt had a weighted average life to maturity of 8.7 years and a weighted average interest rate of 5.6 percent. In 2004, the company issued $997 million in long-term debt.

In May 2004, the company issued $600 million of senior unsecured notes, consisting of $300 million of 4.75-percent fixed-rate, five-year notes and $300 million of four-year, floating-rate notes. The proceeds of the issuance were used to repay $500 million of debt maturing July 1, 2004, and for general corporate purposes.

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

In December 2004, SoCalGas issued $100 million of floating rate first mortgage bonds maturing in December 2009. The interest rate is based on the 3-month LIBOR rate plus 0.17%.

Repayments on long-term debt in 2004 included the $500 million of notes payable that matured in July 2004, $426 million of first mortgage bonds and $66 million of rate-reduction bonds. Also in 2004, Sempra Generation purchased the assets of Mesquite Trust, thereby extinguishing $630 million of debt outstanding, and Sempra Financial repaid $34 million of debt incurred to acquire limited partnership interests.

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, Sempra Financial 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.

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 average market price. In addition, Sempra Generation 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.

In May 2004, the California Utilities obtained a combined $500 million three-year syndicated revolving credit facility to replace their expiring 364-day facility of a like amount. No amounts were outstanding under this facility at December 31, 2004. SoCalGas had $30 million of commercial paper outstanding at December 31, 2004.

In May 2004, the company entered into an interest-rate swap agreement that effectively changed the interest rate on $300 million of 7.95% notes (issued in February 2000) from fixed to floating. The swap is set to expire in 2010, the same year the related debt matures.

In June 2004, Sempra Commodities obtained a two-year syndicated revolving line of credit providing for extensions of credit (consisting of borrowings, letters of credit and other credit support accommodations) to Sempra Commodities and certain of its affiliates of up to $1 billion. At December 31, 2004, outstanding extensions of credit under the facility totaled $489 million, of which $439 million was in the form of letters of credit.

In July 2004, Sempra Global obtained a $1.5 billion three-year syndicated revolving credit facility to replace its expiring $500 million revolving credit facility and the expiring $400 million revolving credit facility of Sempra Generation. Sempra Global continues to have a substantially identical $500 million three-year revolving credit facility that expires in 2006. Sempra Global had $36 million outstanding under these lines at December 31, 2004. Sempra Global also had $220 million of commercial paper, guaranteed by Sempra Energy, outstanding at December 31, 2004. There was no commercial paper outstanding at December 31, 2003.

In September 2004, Pacific Enterprises (PE) extended the termination date of its revolving credit agreement to September 30, 2005 and increased the revolving credit commitment from $250 million to $500 million. No amounts were outstanding under this facility at December 31, 2004.

In December 2004, Sempra LNG obtained a $1.25 billion five-year syndicated revolving credit facility. The $1.25 billion also provides for the issuance of letters of credit not exceeding $200 million outstanding at any one time. No amounts were outstanding under this facility at December 31, 2004.

Notes 5 and 6 of the notes to Consolidated Financial Statements provide 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 in Note 13 of the notes to Consolidated Financial Statements. In February 2005, the company remarketed the senior notes included in the equity units for their remaining term at a rate of 4.62%.

In March 2000, the company's board of directors authorized the optional expenditure of up to $100 million to repurchase shares of common stock from time to time in the open market or in privately negotiated transactions. Under this authorization, the company acquired 162,400 shares in 2000, 60,000 shares in 2001 and 674,400 shares in 2002.

Dividends

Dividends paid on common stock were $195 million in 2004, $182 million in 2003 and $201 million in 2002. On February 18, 2005, the company's board of directors approved an increase in the quarterly dividend from $0.25 per share to $0.29 per share.

The payment and amount of future dividends 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, 2004, SDG&E and SoCalGas could have provided a total (combined loans and dividends) of $160 million and $200 million, respectively, to Sempra Energy.

Capitalization

Total capitalization, including short-term debt and the current portion of long-term debt and excluding the rate-reduction bonds (which are non-recourse to the company), at December 31, 2004 was $9.8 billion. The debt-to-capitalization ratio was 49 percent at December 31, 2004. Significant changes affecting capitalization during 2004 included common stock issuances, long-term borrowings and repayments, short-term borrowings, income and dividends.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2004. Trading liabilities are not included herein as such derivative transactions are primarily offset by 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 5, 6, 9, 12 and 16 of the notes to Consolidated Financial Statements.

(Dollars in millions)	2005	2006 and 2007	2008 and 2009	Thereafter	Total
Short-term debt	$ 405	$ —	$ —	$ —	$ 405
Long-term debt	398	785	735	2,672	4,590
Interest on debt (1)	236	393	313	853	1,795
Due to unconsolidated affiliates	205	—	62	100	367
Preferred stock of subsidiaries subject to mandatory redemption	2	2	17	—	21
Operating leases	107	190	166	178	641
Purchased-power contracts	256	592	701	4,035	5,584
Natural gas contracts	1,099	481	41	189	1,810
Construction commitments	356	401	16	49	822
Topaz Power Partners guarantee	75	—	—	—	75
Twin Oaks coal supply	31	55	54	285	425
SONGS decommissioning	16	13	4	295	328
Other asset retirement obligations	5	9	1	5	20
Pension and postretirement benefit obligations (2)	217	477	510	1,463	2,667
Environmental commitments	18	36	—	—	54
Other	24	50	52	249	375
Totals	$3,450	$3,484	$2,672	$10,373	$19,979

(1) Based on rates in effect at December 31, 2004.

(2) Amounts are before reduction for the Medicare Part D subsidy and only include expected payments for the next 10 years.

Credit Ratings

Credit ratings of the company and its principal subsidiaries remained unchanged at investment grade levels in 2004. As of January 31, 2005, credit ratings for Sempra Energy and its principal subsidiaries were as follows:

	Standard & Poor's	Moody's Investor Services, Inc.	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
SEMPRA GLOBAL			
Unsecured debt guaranteed by Sempra Energy	—	Baa1	—
Commercial paper guaranteed by Sempra Energy	A-2	P-2	F1

As of January 31, 2005, the company has a stable outlook rating from all three credit rating agencies. During 2004, Standard & Poor's implemented new standards to assess liquidity requirements under certain predetermined stress scenarios, primarily related to Sempra Commodities. Participation in this program has not affected Standard & Poor's ratings of the company.

FACTORS INFLUENCING FUTURE PERFORMANCE

The California Utilities' and Sempra Generation's long-term contracts generally provide relatively stable earnings, while Sempra Generation, Sempra Pipelines & Storage and Sempra LNG provide opportunities for earnings growth and Sempra Commodities experiences significant volatility in earnings. Notes 14 through 16 of the notes to Consolidated Financial Statements also describe matters that could affect future performance.

Litigation

Note 16 describes significant litigation against the company, primarily cases arising from the California energy crisis and Sempra Generation's contract with the DWR.

California Utilities

Notes 14, 15 and 16 of the notes to Consolidated Financial Statements describe electric and natural gas restructuring and rates, the recent cost of service proceedings, and the CPUC's investigations of natural gas prices at the California-Arizona border.

Sempra Global

Electric-Generation Assets

As discussed in Note 2 of the notes to Consolidated Financial Statements, the company is involved in the expansion of its electric-generation capabilities, including the acquisition of the plants that now comprise Topaz, which will affect the company's future performance.

Investments

As discussed in "Cash Flows From Investing Activities," the company's investments will significantly impact the company's future performance.

Sempra LNG is in the process of developing Energía Costa Azul, an LNG receiving terminal in Baja California, Mexico; the Cameron LNG receiving terminal in Louisiana; and the Port Arthur LNG receiving terminal in Texas. In addition, in December 2004, Sempra LNG entered into a non-binding development agreement with Alaska Gasline Port Authority to jointly consider and analyze the feasibility of building a proposed 800-mile gas pipeline from Alaska's North Slope to Valdez, where a gas liquefaction facility could be developed to export LNG to the rest of North America. The future profitability of this business unit is dependent upon numerous factors, including the quantities of and relative prices of natural gas in North America and from LNG suppliers located elsewhere, negotiating sale and supply contracts at adequate margins, acquiring all necessary permits and completing cost-effective construction of the required facilities. Additional information regarding these activities is provided above in "Cash Flows From Investing Activities" and in Note 2 of the notes to Consolidated Financial Statements.

Beginning in 2003, the company started expanding its natural gas storage capacity by developing Bluewater Gas Storage, LLC, located in Michigan. In April 2004, the company announced the acquisition of land and associated rights for the development of a salt-cavern natural gas storage facility in Evangeline Parish, Louisiana, operating as the Pine Prairie Energy Center. In July 2004, the company announced that it had acquired the rights to develop Liberty Gas Storage, a salt-cavern gas storage facility located in Calcasieu Parish, Louisiana. Additional information regarding these activities is provided in Note 2 of the notes to Consolidated Financial Statements.

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. Information regarding this situation is provided in Notes 3 and 16 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 and other 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, the company's subsidiaries 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 company subsidiaries. Historical volatilities and correlations between instruments and positions are used in the calculation.

Following is a summary of Sempra Commodities' trading VaR profile (using a one-day holding period) in millions of dollars:

	95%	99%
December 31, 2004	**$8.0**	**$11.3**
2004 range	**$2.8 to $ 18.7**	**$3.9 to $ 26.1**
December 31, 2003	$2.6	$3.7
2003 range	$2.2 to $ 34.0	$3.1 to $ 47.6

The California Utilities use energy and natural 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.

Revenue recognition is discussed in Notes 1 and 11 and the additional market risk information regarding derivative instruments is discussed in Note 11 of the notes to Consolidated Financial Statements.

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

Commodity Price Risk

Market risk related to physical commodities is created by volatility in the prices and basis of 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 Commodities

Sempra Commodities derives most of its revenue from its worldwide trading activities in natural gas, electricity, petroleum products, metals and other commodities. As a result, Sempra Commodities is exposed to price volatility in the related domestic and international markets. Sempra Commodities 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.

California Utilities

With respect to the California Utilities, market risk exposure is limited due to CPUC-authorized rate recovery of the costs 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 Note 15 of the notes to Consolidated Financial Statements. If commodity prices were to rise too rapidly, it is likely that volumes would decline. This would increase the per-unit fixed costs, which could lead to further volume declines. The California Utilities manage their risk within the parameters of the company's market risk management framework. As of December 31, 2004, the total VaR of the California Utilities' natural gas and electric positions was not material.

Interest Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its long-term debt. The company historically has funded utility operations through long-term debt issues with fixed interest rates and these interest rates are recovered in utility rates. Some recent debt offerings have used a combination of fixed-rate and floating-rate debt. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures.

At December 31, 2004, the California Utilities had $1.7 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, 2004, utility fixed-rate debt had a one-year VaR of $214 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, 2004, with a one-year VaR of $101 million.

At December 31, 2004, the notional amount of interest-rate swap transactions totaled $701 million. Note 6 of the notes to Consolidated Financial Statements provides further information regarding interest-rate swap transactions.

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

Credit Risk

Credit risk is the risk of loss that would be incurred as a result of nonperformance by counterparties of their contractual obligations. As with market risk, the company has adopted corporate-wide policies governing the management of credit risk. Credit risk management is performed by the ERMG and the California Utilities' credit department and overseen by the ERMOC. Using rigorous models, the ERMG and the company calculate current and potential credit risk to counterparties on a daily basis and monitor actual balances in comparison to approved limits. The company avoids concentration of counterparties whenever possible, and management believes its credit policies associated with counterparties significantly reduce overall credit risk. These policies include an evaluation of prospective counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty, and other security such as lock-box liens and downgrade triggers. At December 31, 2004, Sempra Commodities' 20 largest customers had balances of $21 million to $80 million each. The company believes that adequate reserves have been provided for counterparty nonperformance.

As described in Note 16 of the notes to Consolidated Financial Statements, Sempra Generation has a contract with the DWR to supply up to 1,900 MW of power to the state of California 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 developing LNG projects will result in significant reliance on the credit-worthiness of its major suppliers and customers of those projects.

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

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

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, Sempra Pipelines & Storage has reduced the carrying value of its Argentine investments downward by a cumulative total of $198 million as of December 31, 2004. 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). Further discussion is provided 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, 2004, the company had no significant arrangements of this type.

The company's primary objective with respect to currency risk is to preserve the economic value of its overseas investments and 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 rate-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 of the notes to Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND KEY NON-CASH PERFORMANCE INDICATORS

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

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

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 16 of the notes to Consolidated Financial Statements.

SFAS 71, "Accounting for the Effects of Certain Types of Regulation," has a significant effect on the way the California Utilities record assets and liabilities, and the related revenues and expenses that would not be recorded absent the principles contained in SFAS 71.

SFAS 109, "Accounting for Income Taxes," governs the way the company provides for income taxes. Details of the company's issues in this area are discussed in Note 8 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 has elected the disclosure-only option for all options that are so eligible. The effect of this is discussed in Note 1 of the notes to Consolidated Financial Statements.

SFAS 123R, "Share-Based Payment," requires public companies to measure and record the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the awards and gives companies three methods to do so. This statement is effective for the company on July 1, 2005. Further discussion is provided in Note 1 of the notes to Consolidated Financial Statements.

SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" and SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," have a significant effect on the balance sheets of Sempra Commodities 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 Sempra Commodities' income statement is discussed in Note 11 of the notes to Consolidated Financial Statements.

Emerging Issues Task Force (EITF) Issue 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 Sempra Commodities, 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 Sempra Commodities are now covered by SFAS 133, SFAS 138 and SFAS 149, which have a similar effect.

SFAS 52, "Foreign Currency Translation," is critical to the accounting for the company's international operations. The application of SFAS 52 is materially affected by the company's accounting treatment of certain U.S. dollar-denominated loans to its Argentine affiliates as though they were equity (based on expectations that repayment will not occur in the foreseeable future), which results in there not being any currency transaction gains or losses when the exchange rate between the currencies changes.

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 adopted FIN 46 on December 31, 2003, resulting in the consolidation of two VIEs for which FIN 46 deems it to be the primary beneficiary. One of the VIEs was the owner of the Mesquite Power plant. The other VIE relates to the investment in AEG. The primary effect of adopting FIN 46 was reflected in the 2003 Statement of Consolidated Income. These VIEs are discussed further 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 resolution of various income-tax issues between the company and the various taxing authorities.

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 probable costs to be incurred in the resolution of litigation.

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

As discussed elsewhere herein, the company uses exchange quotations or other third-party pricing to estimate fair values whenever possible. When no such data is available, it uses internally developed models and other techniques. The assumed collectibility of receivables considers the aging of the receivables, the credit-worthiness of customers and the enforceability of contracts, where applicable. The assumed collectibility of regulatory assets considers legal and regulatory decisions involving the specific items or similar items. The assumed collectibility of other assets considers the nature of the item, the enforceability of contracts where applicable, the credit-worthiness of the other parties and other factors. The anticipated resolution of income-tax issues considers past resolutions of the same or similar issue, the status of any income-tax examination in progress and positions taken by taxing authorities with other taxpayers with similar issues. 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 Sempra Generation's generating plants. Sempra Commodities 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 "Overview" and "Results of Operations." For competitive reasons, Sempra Generation does not disclose its plant availability factors, but considers them to be very good. The table under "Net Income by Business Unit — Sempra Commodities" provides the information for Sempra Commodities.

Other than its two small natural gas utilities in the eastern United States, Sempra Pipelines & Storage'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 2004. The pipeline system had contracted capacity of 450 million cubic feet per day in 2004 and 2003.

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had a significant effect on the company's financial statements are SFAS 132 (revised 2003), 143, 144 and 150, FIN 46, FASB Staff Position (FSP) 106-2 and the rescission of EITF 98-10. They are described in Note 1 of the notes to Consolidated Financial Statements. Pronouncements of particular importance to the company's financial statements are described below.

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,* 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.

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.

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) was the owner of the Mesquite Power plant for which the company had a synthetic lease agreement as described in Note 2 of the notes to Consolidated Financial Statements. The company bought out the lease in January 2004 and now owns the plant. The other VIE relates to the company's investment in AEG, which was subsequently disposed of in April 2004. 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. Further discussion regarding FIN 46 is provided in Note 1 of the notes to Consolidated Financial Statements.

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

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 State Legislature, the California Department of Water Resources, and the Federal Energy Regulatory Commission and other regulatory bodies in the United States and other countries; capital markets conditions, inflation rates, interest rates and exchange rates; energy and trading markets, including the timing and extent of changes in commodity prices; the availability of natural gas; weather conditions and conservation efforts; war and terrorist attacks; business, regulatory, environmental and legal decisions and requirements; the status of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company’s business described in this report and other reports filed by the company from time to time with the Securities and Exchange Commission.

FIVE YEAR SUMMARY

At December 31 or for the years ended December 31,
(Dollars in millions, except per share amounts)

	2004	2003	2002	2001	2000
Operating revenues					
California utilities:					
Natural Gas	**$ 4,537**	$ 4,010	$ 3,263	$ 4,371	$ 3,305
Electric	**1,658**	1,787	1,282	1,676	2,184
Other	**3,215**	2,090	1,503	1,683	1,271
Total	**$ 9,410**	$ 7,887	$ 6,048	$ 7,730	$ 6,760
Operating income	**$ 1,272**	$ 939	$ 987	$ 997	$ 884
Income from continuing operations, before extraordinary item and cumulative effect of changes in accounting principles	**$ 920**	$ 695	$ 575	$ 518	$ 429
Net income	**$ 895**	$ 649	$ 591	$ 518	$ 429
Income per common share from continuing operations before extraordinary item and cumulative effect of changes in accounting principles:					
Basic	**$ 4.03**	$ 3.29	$ 2.80	$ 2.54	$ 2.06
Diluted	**$ 3.93**	$ 3.24	$ 2.79	$ 2.52	$ 2.06
Net income per common share:					
Basic	**$ 3.92**	$ 3.07	$ 2.88	$ 2.54	$ 2.06
Diluted	**$ 3.83**	$ 3.03	$ 2.87	$ 2.52	$ 2.06
Dividends declared per common share	**$ 1.00**	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Return on common equity	**20.5%**	19.3%	21.4%	19.5%	15.7%
Effective income tax rate	**17.3%**	6.3%	20.2%	29.1%	38.6%
Price range of common shares	**$ 37.93-29.51**	$ 30.90-22.25	$ 26.25-15.50	$ 28.61-17.31	$ 24.88-16.19
Weighted average rate base:					
SoCalGas	**$ 2,351**	$ 2,273	$ 2,222	$ 2,262	$ 2,329
SDG&E	**$ 2,755**	$ 2,619	$ 2,452	$ 2,334	$ 2,263
AT DECEMBER 31					
Current assets	**$ 8,776**	$ 7,866	$ 7,010	$ 4,692	$ 6,525
Total assets	**$23,643**	$21,988	$20,242	$17,378	$17,850
Current liabilities	**$ 9,082**	$ 8,569	$ 7,554	$ 5,629	$ 7,490
Long-term debt (excludes current portion)	**$ 4,192**	$ 3,841	$ 4,083	$ 3,436	$ 3,268
Trust preferred securities	**$ 200***	$ 200*	$ 200	$ 200	$ 200
Shareholders' equity	**$ 4,865**	$ 3,890	$ 2,825	$ 2,692	$ 2,494
Common shares outstanding (in millions)	**234.2**	226.6	204.9	204.5	201.9
Book value per common share	**$ 20.77**	$ 17.17	$ 13.79	$ 13.16	$ 12.35

* Amount has been reclassified to Due to Unconsolidated Affiliates effective in 2003.

Note 1 of the notes to consolidated financial statements discusses the changes in accounting principles and the extraordinary item. Note 4 discusses the discontinued operation. Note 16 discusses litigation and other contingences.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

Deloitte & Touche LLP, an independent registered public accounting firm, audits the company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and provides an objective, independent review of the fairness of reported operating results and financial position.

The board of directors of the company has an Audit Committee composed of six non-management directors. The committee meets periodically with financial management, the internal auditors and Deloitte & Touche LLP to review accounting, control, auditing and financial reporting matters.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Sempra Energy:

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

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

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

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

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

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

Deloitte & Touche LLP

San Diego, California
February 22, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2004 and 2003, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sempra Energy and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

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

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.

Deloitte & Touche LLP

San Diego, California
February 22, 2005

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME

(Dollars in millions, except per share amounts)	Years ended December 31, 2004	2003	2002
OPERATING REVENUES			
California utilities:			
Natural gas	**$ 4,537**	$ 4,010	$ 3,263
Electric	**1,658**	1,787	1,282
Other	**3,215**	2,090	1,503
Total operating revenues	**9,410**	7,887	6,048
OPERATING EXPENSES			
California utilities:			
Cost of natural gas	**2,593**	2,071	1,381
Cost of electric fuel and purchased power	**576**	541	297
Other cost of sales	**1,741**	1,204	709
Other operating expenses	**2,371**	2,287	1,901
Depreciation and amortization	**621**	615	596
Franchise fees and other taxes	**236**	230	177
Total operating expenses	**8,138**	6,948	5,061
Operating income	**1,272**	939	987
Other income, net	**104**	26	15
Interest income	**69**	104	42
Interest expense	**(322)**	(308)	(294)
Preferred dividends of subsidiaries	**(10)**	(10)	(11)
Trust preferred distributions by subsidiary	**—**	(9)	(18)
Income from continuing operations before income taxes	**1,113**	742	721
Income tax expense	**193**	47	146
Income from continuing operations	**920**	695	575
Loss from discontinued operations, net of tax (Note 4)	**(23)**	—	—
Loss on disposal of discontinued operations, net of tax (Note 4)	**(2)**	—	—
Income before extraordinary item and cumulative effect of changes in accounting principles	**895**	695	575
Extraordinary item, net of tax (Note 1)	**—**	—	16
Income before cumulative effect of changes in accounting principles	**895**	695	591
Cumulative effect of changes in accounting principles, net of tax (Note 1)	**—**	(46)	—
Net income	**$ 895**	$ 649	$ 591
Basic earnings per share:			
Income from continuing operations	**$ 4.03**	$ 3.29	$ 2.80
Discontinued operations, net of tax	**(0.11)**	—	—
Extraordinary item, net of tax	**—**	—	0.08
Cumulative effect of changes in accounting principles, net of tax	**—**	(0.22)	—
Net income	**$ 3.92**	$ 3.07	$ 2.88
Weighted-average number of shares outstanding (thousands)	**228,271**	211,740	205,003
Diluted earnings per share:			
Income from continuing operations	**$ 3.93**	$ 3.24	$ 2.79
Discontinued operations, net of tax	**(0.10)**	—	—
Extraordinary item, net of tax	**—**	—	0.08
Cumulative effect of changes in accounting principles, net of tax	**—**	(0.21)	—
Net income	**$ 3.83**	$ 3.03	$ 2.87
Weighted-average number of shares outstanding (thousands)	**233,852**	214,482	206,062
Dividends declared per share of common stock	**$ 1.00**	$ 1.00	$ 1.00

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	**December 31, 2004**	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 419**	$ 409
Short-term investments	**15**	386
Trade accounts receivable, net	**950**	749
Other accounts and notes receivable, net	**82**	125
Due from unconsolidated affiliate	**4**	—
Deferred income taxes	**15**	—
Interest receivable	**80**	62
Trading-related receivables and deposits, net	**2,606**	2,350
Derivative trading instruments	**2,339**	1,607
Commodities owned	**1,547**	1,420
Regulatory assets arising from fixed-price contracts and other derivatives	**152**	144
Other regulatory assets	**103**	89
Inventories	**172**	147
Other	**222**	158
Current assets of continuing operations	**8,706**	7,646
Current assets of discontinued operations	**70**	220
Total current assets	**8,776**	7,866
Investments and other assets:		
Due from unconsolidated affiliates	**42**	55
Regulatory assets arising from fixed-price contracts and other derivatives	**500**	650
Other regulatory assets	**619**	552
Nuclear decommissioning trusts	**612**	570
Investments	**1,164**	1,112
Sundry	**844**	707
Total investments and other assets	**3,781**	3,646
Property, plant and equipment:		
Property, plant and equipment	**16,203**	15,319
Less accumulated depreciation and amortization	**(5,117)**	(4,843)
Property, plant and equipment, net	**11,086**	10,476
Total assets	**$23,643**	$21,988

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2004	December 31, 2003
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	**$ 405**	$ 28
Accounts payable — trade	**1,020**	725
Accounts payable — other	**106**	63
Due to unconsolidated affiliates	**205**	1
Income taxes payable	**187**	336
Deferred income taxes	**—**	31
Trading-related payables	**3,182**	2,255
Derivative trading instruments sold, not yet purchased	**1,484**	1,340
Commodities sold with agreement to repurchase	**513**	922
Dividends and interest payable	**123**	136
Regulatory balancing accounts, net	**509**	424
Fixed-price contracts and other derivatives	**157**	148
Current portion of long-term debt	**398**	1,433
Other	**776**	675
Current liabilities of continuing operations	**9,065**	8,517
Current liabilities of discontinued operations	**17**	52
Total current liabilities	**9,082**	8,569
Long-term debt	**4,192**	3,841
Deferred credits and other liabilities:		
Due to unconsolidated affiliates	**162**	362
Customer advances for construction	**97**	89
Postretirement benefits other than pensions	**129**	131
Deferred income taxes	**420**	368
Deferred investment tax credits	**78**	84
Regulatory liabilities arising from cost of removal obligations	**2,359**	2,238
Regulatory liabilities arising from asset retirement obligations	**333**	303
Other regulatory liabilities	**67**	109
Fixed-price contracts and other derivatives	**500**	680
Asset retirement obligations	**326**	313
Deferred credits and other	**854**	832
Total deferred credits and other liabilities	**5,325**	5,509
Preferred stock of subsidiaries	**179**	179
Commitments and contingencies (Note 16)		
SHAREHOLDERS' EQUITY		
Preferred stock (50 million shares authorized; none issued)	**—**	—
Common stock (750 million shares authorized; 234 million and 227 million shares outstanding at December 31, 2004 and 2003, respectively)	**2,301**	2,028
Retained earnings	**2,961**	2,298
Deferred compensation relating to ESOP	**(32)**	(35)
Accumulated other comprehensive income (loss)	**(365)**	(401)
Total shareholders' equity	**4,865**	3,890
Total liabilities and shareholders' equity	**$23,643**	$21,988

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years ended December 31, **2004**	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 895**	$ 649	$ 591
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations, net of tax	**25**	—	—
Depreciation and amortization	**621**	615	596
Deferred income taxes and investment tax credits	**13**	(118)	(143)
Non-cash rate reduction bond expense	**75**	68	82
Equity in (income) losses of unconsolidated affiliates	**(36)**	(8)	55
Impairment losses	**12**	101	—
Loss (gain) on sale and disposition of assets	**(15)**	8	14
Foreign currency loss (gain)	**—**	8	(63)
Extraordinary item, net of tax	**—**	—	(16)
Cumulative effect of changes in accounting principles, net of tax	**—**	46	—
Other, net	**37**	23	(2)
Net changes in other working capital components	**(427)**	(154)	203
Changes in other assets	**(200)**	(71)	84
Changes in other liabilities	**(21)**	(26)	40
Net cash provided by continuing operations	**979**	1,141	1,441
Net cash used in discontinued operations	**(30)**	—	—
Net cash provided by operating activities	**949**	1,141	1,441
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	**(1,083)**	(1,049)	(1,214)
Investments in and acquisitions of subsidiaries, net of cash acquired	**(74)**	(202)	(429)
Proceeds from disposal of discontinued operations	**157**	—	—
Proceeds from sale of assets	**372**	29	—
Dividends received from unconsolidated affiliates	**59**	72	11
Affiliate loans	**—**	(99)	(82)
Other, net	**10**	1	(9)
Net cash used in investing activities	**(559)**	(1,248)	(1,723)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common dividends paid	**(195)**	(182)	(201)
Issuances of common stock	**110**	505	9
Repurchases of common stock	**(5)**	(7)	(17)
Issuances of long-term debt	**997**	900	1,150
Payments on long-term debt	**(1,670)**	(601)	(479)
Increase (decrease) in short-term debt, net	**397**	(518)	(307)
Other, net	**(14)**	(8)	(18)
Net cash (used in) provided by financing activities	**(380)**	89	137
Increase (decrease) in cash and cash equivalents	**10**	(18)	(145)
Cash and cash equivalents, January 1	**409**	427	572
Cash and cash equivalents, December 31	**$ 419**	$ 409	$ 427

See notes to Consolidated Financial Statements.

	Years ended December 31,		
	2004	2003	2002
CHANGES IN OTHER WORKING CAPITAL COMPONENTS			
(Excluding cash and cash equivalents, and debt due within one year)			
Accounts and notes receivable	**$(346)**	$(231)	$ (121)
Net trading assets	**(442)**	81	66
Income taxes, net	**(66)**	72	137
Inventories	**(25)**	(13)	(11)
Regulatory balancing accounts	**79**	(156)	170
Regulatory assets and liabilities	**(23)**	(30)	1
Other current assets	**(31)**	(8)	51
Accounts payable	**324**	98	(103)
Other current liabilities	**103**	33	13
Net changes in other working capital components	**$(427)**	$(154)	$ 203
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	**$ 318**	$ 296	$ 279
Income tax payments, net of refunds	**$ 254**	$ 118	$ 140
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Common dividends paid in stock	**$ 35**	$ 25	$ 4
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, 2004, 2003 and 2002

(Dollars in millions)	Comprehensive Income	Common Stock	Retained Earnings	Deferred Compensation Relating to ESOP	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 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 13)		(61)				(61)
Issuance 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
Issuance of common stock		553				553
Tax benefit related to employee stock options		13				13
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
Net income	**$ 895**		**895**			**895**
Comprehensive income adjustments:						
Foreign currency translation gains (Note 1)	**40**				**40**	**40**
Pension	**28**				**28**	**28**
Available-for-sale securities	**4**				**4**	**4**
SFAS 133	**(36)**				**(36)**	**(36)**
Comprehensive income	**$ 931**					
Common stock dividends declared			**(232)**			**(232)**
Quasi-reorganization adjustment (Note 1)		**86**				**86**
Issuance of common stock		**172**				**172**
Tax benefit related to employee stock options		**16**				**16**
Repurchase of common stock		**(5)**				**(5)**
Common stock released from ESOP		**4**		**3**		**7**
Balance at December 31, 2004		**$2,301**	**$2,961**	**$(32)**	**$(365)**	**$4,865**

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), its majority-owned subsidiaries and the variable-interest entities of which it is the primary beneficiary (as discussed further in New Accounting Standards below). 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. Further discussion of investments in unconsolidated subsidiaries is provided in Note 3. All material intercompany accounts and transactions have been eliminated.

During the fourth quarter of 2004, Sempra Commodities assumed the management of the commodities business of Sempra Energy Solutions, and Sempra Generation assumed the management of Sempra Energy Solutions' other two business lines — energy services and facilities management. Since Sempra Commodities and Sempra Generation are each separate reportable segments of the company, in accordance with Statement of Financial Accounting Standards (SFAS) 131, *Disclosures about Segments of an Enterprise and Related Information*, the prior years' financial statements have been restated to reflect the change in reporting of Sempra Energy Solutions' results of operation and financial position.

Quasi-Reorganization

In 1993, Pacific Enterprises (PE) effected a quasi-reorganization for financial reporting purposes as of December 31, 1992. Certain of the liabilities established in connection with the quasi-reorganization were favorably resolved in 2003 and 2004, resulting in adjustments to common stock in these years. 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 SFAS 71*, Accounting for the Effects of Certain Types of Regulation*, under which a regulated utility records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. To the extent that recovery is no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets would be written off. In addition, SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires that a loss be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase.

Regulatory liabilities represent reductions in future rates for amounts due to customers. Information concerning regulatory assets and liabilities is provided below in “Revenues,” “Regulatory Balancing Accounts” and “Regulatory Assets and Liabilities.”

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2004, represent net payables (payables net of receivables) of $178 million and $331 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 2003 were net payables of $86 million and $338 million, respectively.

Except for certain costs subject to balancing account treatment, fluctuations in most operating and maintenance accounts affect utility earnings. Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. The CPUC has also approved balancing account treatment for variances between forecast and actual for SoCalGas’ and SDG&E’s commodity costs and volumes, eliminating the impact on earnings from any throughput and revenue variances from adopted forecast levels. Additional information on regulatory matters is included in Notes 14 and 15.

Regulatory Assets and Liabilities

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

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

(Dollars in millions)	**2004**	2003
SDG&E		
Fixed-price contracts and other derivatives	**$ 500**	$ 560
Recapture of temporary rate reduction*	**183**	259
Deferred taxes recoverable in rates	**278**	271
Unamortized loss on retirement of debt, net	**46**	44
Employee benefit costs	**160**	35
Cost of removal obligation**	**(913)**	(846)
Asset retirement obligation**	**(333)**	(303)
Other	**29**	24
Total	**(50)**	44
SoCalGas		
Fixed-price contracts and other derivatives	**148**	233
Environmental remediation	**42**	44
Unamortized loss on retirement of debt, net	**44**	45
Cost of removal obligation**	**(1,446)**	(1,392)
Deferred taxes refundable in rates	**(199)**	(194)
Employee benefit costs	**65**	(77)
Other	**7**	9
Total	**(1,339)**	(1,332)
PE — Employee benefit costs (transferred to SoCalGas in 2004)	**—**	72
Total PE consolidated	**(1,339)**	(1,260)
Total	**$(1,389)**	$(1,216)

* In connection with electric industry restructuring, which is described in Note 14, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2007.

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

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

(Dollars in millions)	**2004**	2003
Current regulatory assets	**$ 255**	$ 233
Noncurrent regulatory assets	**1,119**	1,202
Current regulatory liabilities*	**(4)**	(1)
Noncurrent regulatory liabilities	**(2,759)**	(2,650)
Total	**$(1,389)**	$(1,216)

* Included in Other Current Liabilities.

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

Cash and Cash Equivalents

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

Restricted cash

Restricted cash was $15 million and $23 million at December 31, 2004 and 2003, respectively. The amounts are included in current assets under the caption Short-term Investments and are primarily used to serve as cash collateral for certain debt agreements.

Collection Allowances

The allowance for doubtful accounts was $8 million, $19 million and $12 million at December 31, 2004, 2003 and 2002, respectively. The company recorded a provision for doubtful accounts of $12 million, $5 million and $13 million in 2004, 2003 and 2002, respectively.

The allowance for realization of trading assets was $56 million, $67 million and $86 million at December 31, 2004, 2003 and 2002, respectively. The company recorded a provision (reduction thereof) for trading assets of $3 million, $(4) million and $20 million in 2004, 2003 and 2002, respectively.

Trading Instruments

Trading assets and trading liabilities (described further in Note 11) 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. Trading instruments are recorded by Sempra Commodities 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.

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, as discussed 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 continues to be recorded at fair value in accordance with Accounting Research Bulletin (ARB) No. 43*, Restatement and Revision of Accounting Research Bulletins.* Further discussion of EITF Issue 98-10 is provided 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.

Inventories

At December 31, 2004, inventory shown on the Consolidated Balance Sheets, which does not include Commodities Owned, included natural gas of $115 million, and materials and supplies of $57 million. The corresponding balances at December 31, 2003 were $89 million and $58 million, respectively. Natural gas at the California Utilities ($111 million and $84 million at December 31, 2004 and 2003, 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.

Income Taxes

Income tax expense includes current and deferred income taxes from operations during the year. In accordance with SFAS 109, *Accounting for Income Taxes*, the company records deferred income taxes for temporary differences between the book and tax bases of assets and liabilities. Investment tax credits from prior years are being amortized to income by the California Utilities over the estimated service lives of the properties. Other credits, mainly low-income housing and synthetic-fuel tax credits, are recognized in income as earned. The company follows certain provisions of SFAS 109 that permit regulated enterprises to recognize deferred taxes as regulatory assets or liabilities if it is probable that such amounts will be recovered from, or returned to, customers. The company follows Accounting Principles Board Opinion (APBO) 23, *Accounting for Income Taxes — Special Areas*, in recording deferred taxes for investments in foreign subsidiaries and the undistributed earnings of foreign subsidiaries.

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 by Sempra Generation.

The cost of plant includes labor, materials, contract services and certain expenditures, including refurbishments, replacement of major component parts and labor and overheads incurred to install the parts, incurred during a major maintenance outage of a generating plant. Maintenance costs are expensed as incurred. In addition, the cost of 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)	**2004**	2003	**2004**	2003	2002
California Utilities:					
Natural gas operations	**$ 8.1**	$ 7.8	**3.65%**	4.27%	4.25%
Electric distribution	**3.4**	3.2	**4.11%**	4.70%	4.66%
Electric transmission	**1.0**	0.9	**3.06%**	3.09%	3.17%
Construction work in progress	**0.5**	0.4	**NA**	NA	NA
Other electric	**0.6**	0.5	**11.33%**	9.53%	9.37%
Total	**13.6**	12.8			
Other operations:					
Land and land rights	**0.1**	0.1			
Buildings and leasehold improvements	**0.2**	0.2			
Machinery and equipment	**1.9**	1.8			
Construction work in progress	**0.3**	0.3			
Other	**0.1**	0.1			
	2.6	2.5	**various**	various	various
Total	**$16.2**	$15.3			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $3.3 billion and $1.4 billion, respectively, at December 31, 2004, and were $3.1 billion and $1.4 billion, respectively, at December 31, 2003. The discussion of SFAS 143 under “New Accounting Standards” describes a change in presentation of accumulated depreciation. Depreciation expense is based on the straight-line method over the useful lives of the assets or, for the California Utilities, a shorter period prescribed by the CPUC. Notes 14 and 15 include a discussion of the industry restructuring, which affected recorded depreciation. Accumulated depreciation for power plants at Sempra Generation was $47 million and $17 million at December 31, 2004 and 2003, respectively. Depreciation expense is computed using the straight-line method over the asset’s estimated original composite useful life or the remaining term of the site leases, whichever is lower.

AFUDC, which represents the cost of debt and equity funds used to finance the construction of utility plant, is added to the cost of utility plant. Although it is not a current source of cash, AFUDC increases income and is recorded partly as an offset to interest charges and partly as a component of Other Income, Net in the Statements of Consolidated Income. AFUDC amounted to $18 million, $29 million and $34 million for 2004, 2003 and 2002, respectively. Total capitalized carrying costs, including AFUDC and the impact of Sempra Generation’s construction projects, were $27 million, $55 million and $63 million for 2004, 2003 and 2002, respectively.

Goodwill and Intangible Assets

Goodwill represents the excess of the purchase price over the fair value of the net assets of acquired companies. Goodwill is not amortized, but is tested annually for impairment in accordance with SFAS 142, *Goodwill and Other Intangible Assets*.

In accordance with the transitional guidance of SFAS 142, recorded goodwill attributable to the company was tested for impairment in 2002 by comparing its fair value to its carrying value, using a discounted cash flow methodology. As a result, in 2002, Sempra Pipelines & Storage 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. Also during 2002, Sempra Commodities completed several acquisitions as further discussed in Note 2. As a result of Sempra Commodities' 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, which reflected a tax benefit of $2 million, was recorded in 2002 related to the purchase of the base metals and concentrates businesses at prices below the net sums of the fair values of the assets and liabilities acquired.

During 2003, Sempra Pipelines & Storage purchased the remaining minority interests in its Mexican subsidiaries, which resulted in the recording of an addition to goodwill of $6 million and of another intangible asset of $4 million.

The changes in the carrying amount of goodwill (included in Noncurrent Sundry Assets on the Consolidated Balance Sheets) since January 1, 2003 are as follows:

(Dollars in millions)	Sempra Commodities	Sempra Generation	Other	Total
Balance as of January 1, 2003	$164	$18	$—	$182
Goodwill acquired during 2003	—	—	6	6
Balance as of December 31, 2003 and 2004	$164	$18	$ 6	$188

Sempra Commodities and Sempra Generation are the only reportable segments that have 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 $296 million and $299 million at December 31, 2004 and 2003, respectively, before foreign-currency translation adjustments. Including foreign-currency translation adjustments, these amounts were $238 million and $232 million, respectively. Other intangible assets were not material at December 31, 2004 or 2003.

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, the definition of which does not include unconsolidated subsidiaries. Impairment of long-lived assets 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. Further discussion of SFAS 144 is provided in "New Accounting Standards." During the third and fourth quarters of 2003, the company recorded before-tax impairment charges of $77 million and $24 million, respectively, 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 and in Note 4. The carrying value of unconsolidated subsidiaries is evaluated for impairment based on the requirements of APBO 18, *The Equity Method of Accounting for Investments in Common Stock*.

Nuclear Decommissioning Liability

At December 31, 2004 and 2003, as the result of implementing SFAS 143, SDG&E had asset retirement obligations of $328 million and $316 million, respectively, and related regulatory liabilities of

$333 million and $303 million, respectively. Additional information on San Onofre Nuclear Generating Station (SONGS) decommissioning costs is included below in "New Accounting Standards."

Legal Fees

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

Comprehensive Income

Comprehensive income includes all changes, except those resulting from investments by owners and distributions to owners, in the equity of a business enterprise from transactions and other events, including foreign-currency translation adjustments, minimum pension liability adjustments and certain hedging activities. The components of other comprehensive income, which consists of all these changes other than net income as shown on the Statements of Consolidated Income, are shown in the Statements of Consolidated Changes in Shareholders' Equity.

The components of Accumulated Other Comprehensive Income, net of income taxes, at December 31, 2004 are as follows:

Foreign-currency translation loss	$(294)
Financial instruments	(39)
Minimum pension liability adjustments	(36)
Unrealized gains on available-for-sale securities	4
Balance as of December 31, 2004	$(365)

Stock-Based Compensation

The company has stock-based employee compensation plans, which are described in Note 10. The company accounts for these plans under the recognition and measurement principles of APBO 25*, Accounting for Stock Issued to Employees,* and related Interpretations. No stock-based employee compensation cost is reflected in net income for options granted after 1998 since those options had an exercise price equal to the market value of the underlying common stock on the date of grant. 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,		
	2004	2003	2002
Net income as reported	**$ 895**	$ 649	$ 591
Stock-based employee compensation expense included in the computation of net income, net of tax (attributable to stock option grants before 1999 and restricted stock awards)	**24**	13	3
Total stock-based employee compensation under fair value method for all grants and awards, net of tax	**(30)**	(20)	(11)
Pro forma net income	**$ 889**	$ 642	$ 583
Earnings per share:			
Basic — as reported	**$3.92**	$3.07	$2.88
Basic — pro forma	**$3.89**	$3.03	$2.84
Diluted — as reported	**$3.83**	$3.03	$2.87
Diluted — pro forma	**$3.80**	$2.99	$2.83

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. Costs associated with long-term contracts allocated to SDG&E from the DWR also were not included in the Statements of Consolidated Income, since the DWR retains legal and financial responsibility for these contracts. Note 14 includes 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 started over at January 1, 2004, essentially eliminating earnings from SONGS except from increases in ratebase in 2004 and beyond.

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

Sempra Commodities 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. Sempra Commodities also earns trading profits as a dealer by structuring and executing transactions. Sempra Commodities utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and volatile fluctuation. 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, Sempra Commodities 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. Sempra Commodities' 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 and, therefore, the related profit or loss will be recognized as the contract is performed. Derivative instruments are discussed further in Note 11.

Sempra Generation's revenues are derived primarily from the sale of electric energy to governmental and wholesale power marketing entities and are recognized in accordance with the provisions of

EITF 91-6, *Revenue Recognition of Long-term Power Supply Contracts,* and EITF 96-17, *Revenue Recognition Under Long-term Power Sales Contracts that Contain Both Fixed and Variable Terms.* During 2004 and 2003, electric energy sales to the DWR accounted for a significant portion of total Sempra Generation's revenues. Additionally, a small portion of Sempra Generation's revenue, formerly included in the operations of Sempra Energy Solutions, is generated from energy related products and services to commercial, industrial, government and institutional markets.

The consolidated foreign subsidiaries of Sempra Pipelines & Storage, 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, Sempra Commodities acquired two businesses for amounts less than the fair values of the businesses' net assets. In accordance with SFAS 141, *Business Combinations*, those differences were recorded as extraordinary income.

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 in Note 3. To reflect the fluctuation in the Argentine peso, the functional currency of the company's Argentine operations, Sempra Pipelines & Storage adjusted its investment in its two Argentine natural gas utility holding companies downward by $1 million, upward by $26 million and downward by $102 million in 2004, 2003 and 2002, respectively. A similar adjustment has been made to its investment in Chile to reflect the fluctuation in the Chilean peso, the functional currency of the company's Chilean operations, upward by $22 million and $43 million in 2004 and 2003, respectively, and downward by $8 million in 2002. These non-cash adjustments did not affect net income, but did reduce or increase 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.

Currency transaction gains and losses in a currency other than the entity's functional currency are included in the calculation of consolidated net income. The company recorded $8 million of currency transaction losses in 2003 and $63 million of gains in 2002. In 2004, the currency transaction gains were not material.

Transactions with Affiliates

Loans to Unconsolidated Affiliates

In December 2001, Sempra Pipelines & Storage 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 (9.02% at December 31, 2004) and are due in January 2006 and June 2005, respectively. The balances outstanding under the notes were $42 million and $55 million at December 31, 2004 and 2003, respectively. These amounts are included in non-current assets under Due from Unconsolidated Affiliates, because they are expected to be refinanced for longer terms.

Loans from Unconsolidated Affiliates

At both December 31, 2004 and 2003, Sempra Pipelines & Storage 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 Energía Finance Co. LLC and are secured by Sempra Pipelines & Storage's investments in Chilquinta Energía S.A. and Luz del Sur S.A.A. (Luz del Sur), which are discussed in Note 3.

In February 2000, a wholly owned subsidiary trust of the company issued 8,000,000 shares of preferred stock in the form of 8.90% Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). The QUIPS have cumulative preferences as to distributions, are nonvoting and have par and liquidation values of $25 per share. Cash dividends are paid quarterly and the QUIPS were scheduled to mature on February 23, 2030, subject to extension to a date not later than February 23, 2049, and shortening to a date not earlier than February 23, 2015. The QUIPS are subject to mandatory redemption and the company has guaranteed payments to the extent that the trust does not have funds available to make distributions. The trust has no assets except its corresponding receivable from Sempra Energy. The QUIPS are callable on or after February 23, 2005 and there are no sinking fund provisions. The company reclassified the $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates as a result of the adoption of Financial Accounting Standard Board Interpretation (FIN) 46 effective December 31, 2003. In addition, dividend payments required on these instruments, previously recorded as Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded as Interest Expense in 2004 and for the last six months of 2003 on the company's Statements of Consolidated Income. The company intends to redeem the $200 million of mandatorily redeemable trust preferred securities prior to the end of February 2005. Therefore, that amount is classified as a current liability under Due to Unconsolidated Affiliates at December 31, 2004.

Revenues and Expenses with Unconsolidated Affiliates

During 2004 and 2003, Sempra Generation recorded $60 million and $61 million, respectively, in sales to El Dorado, an unconsolidated affiliate, and recorded $71 million and $69 million, respectively, of purchases from El Dorado for those same years. Additionally, during 2004, Sempra Commodities recorded $28 million of purchases from Topaz Power Partners (Topaz), an unconsolidated affiliate. The sales to Topaz were not material.

New Accounting Standards

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

SFAS 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits": This statement revised employers' disclosures about pension plans and other postretirement benefit plans. It requires disclosures beyond those in the original SFAS 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement plans. It does not change the measurement or recognition of those plans. Note 9 provides additional information on employee benefit plans.

SFAS 143, "Accounting for Asset Retirement Obligations": Beginning in 2003, SFAS 143 requires entities to record liabilities for future costs expected to be incurred when assets are retired from service, if the retirement process is legally required. It requires recording of the estimated retirement cost over the life of the related asset by depreciating the present value of the obligation (measured at the time of the asset's acquisition) and by accreting the present value of the estimated future obligation over the asset's estimated useful life. The adoption of SFAS 143 on January 1, 2003 resulted in the recording of an addition to utility plant of $71 million, representing the company's share of SONGS' estimated future decommissioning costs (as discounted to the present value at the dates the units began operation), and accumulated depreciation of $41 million related to the increase to utility plant, for a net increase of $30 million. It also requires the reclassification of utilities' estimated removal costs, which had historically been recorded in accumulated depreciation, to a regulatory liability. At December 31, 2004 and 2003, these costs were $1.4 billion at both dates for SoCalGas, and $913 million and $846 million, respectively, for SDG&E. Implementation of SFAS 143 has had no effect on results of operations and is not expected to have a significant effect in the future.

On January 1, 2003, the company recorded additional asset retirement obligations of $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 changes in the asset retirement obligations for the years ended December 31, 2004 and 2003 are as follows (dollars in millions):

	2004	2003
Balance as of January 1	**$337***	$ —
Adoption of SFAS 143	**—**	329
Accretion expense	**24**	22
Payments	**(10)**	(14)
Revision of estimated cash flows	**(3)**	—
Balance as of December 31	**$348***	$337*

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

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

SFAS 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 an impairment loss be recorded if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows.

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

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity": This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that certain mandatorily redeemable financial instruments previously classified in the mezzanine section of the balance sheet be reclassified as liabilities. The company adopted SFAS 150 beginning July 1, 2003 by reclassifying $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 as Preferred Dividends of Subsidiaries and Trust Preferred Distributions, are now recorded as Interest Expense on the company's Statements of Consolidated Income. For the six months ended December 31, 2003, the related amount recorded as interest expense totaled $9 million. On December 31, 2003, the $200 million of mandatorily redeemable trust preferred securities was further reclassified to Due to Unconsolidated Affiliates as a result of the adoption of FIN 46 as discussed below.

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

EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": EITF 98-10 provided for marking to market commodities and arrangements that are not marked to market by SFAS 133 unless certain hedging standards specified in SFAS 133 are complied with. For the company, this consists of certain inventory, and contracts involving transportation and storage. The specified hedging standards have been complied with for a portion of the otherwise-excluded items. A substantial majority of the company's items covered by EITF 98-10 are covered by SFAS 133. 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. Neither the cumulative nor the ongoing effect impacts the company's cash flow or liquidity. Additional information on derivative instruments is provided in Note 11.

FIN 46, "Consolidation of Variable Interest Entities, an interpretation of ARB No. 51": FIN 46, as revised by FIN 46R, requires an enterprise to consolidate a variable interest entity (VIE), as defined in FIN 46, if the company is the primary beneficiary of a VIE's activities. VIEs are enterprises that have certain characteristics defined in FIN 46.

Sempra Energy adopted FIN 46 on December 31, 2003, resulting in the consolidation of two VIEs for which it is the primary beneficiary. One of the VIEs (Mesquite Trust) was the owner of the Mesquite Power plant for which the company had a synthetic lease agreement. The company recorded an after-tax credit of $9 million in the fourth quarter of 2003 for the cumulative effect of the change in accounting principle. The company bought out the lease in January 2004 and now owns the plant.

The other VIE is AEG. Consolidation of AEG resulted in Sempra Energy's recording of 100 percent of AEG's balance sheet and results of operations, whereas it previously recorded only its share of AEG's net operating results. Due to AEG's consolidation, the company recorded an after-tax charge of $26 million in the fourth quarter of 2003 for the cumulative effect of the change in accounting principle. During the first quarter of 2004, Sempra Energy's board of directors approved management's plan to dispose of AEG. Note 4 provides further discussion concerning this matter and the April 2004 disposal of AEG. Had AEG and the Mesquite Trust been consolidated in 2003 and 2002, the company's net income would have been $662 million and $578 million, respectively.

The $46 million cumulative effect recorded in 2003 on the Statements of Consolidated Income, net of the tax benefit of $26 million, consists of the following items which are described above (dollars in millions):

FIN 46:	
Mesquite Trust	$ 9
AEG	(26)
Net charge	(17)
EITF 98-10	(29)
Total charge	$(46)

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

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

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

The company and its actuarial advisors determined that benefits provided to certain participants will actuarially be at least equivalent to Medicare Part D, and, accordingly, the company will be entitled to an expected tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2004 by $102 million and the net postretirement benefit cost for 2004 by $13 million. Employee benefit plans are discussed further in Note 9.

NOTE 2. RECENT ACQUISITIONS AND INVESTMENTS

Sempra Commodities

Sempra Commodities spent $74 million and $27 million in 2004 and 2003, respectively, related to the development of Bluewater Gas Storage, LLC, a natural gas storage facility in Michigan. Sempra Commodities 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 Bluewater Gas Storage facility commenced commercial operations in May 2004.

During 2002, Sempra Commodities completed $119 million of acquisitions that added base metals trading and warehousing to its trading business. In February 2002, Sempra Commodities 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, Sempra Commodities 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, Sempra Commodities 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 further 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. Goodwill of $21 million was recorded in connection with the acquisition of the metals warehousing business.

Sempra Generation

In August 2003, Sempra Generation obtained approvals by the California Energy Commission for the company's 550-megawatt (MW) Palomar power plant in Escondido, California. In June 2004, SDG&E received CPUC approval of its plans to purchase the Palomar plant from Sempra Generation after construction is completed in 2006. Construction of the project began in July 2004.

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, Sempra Generation 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 obligations amounted to $363 million at December 31, 2003. This is included in Short-Term Investments on the Consolidated Balance Sheets at December 31, 2003. 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. Further discussion of this is provided under "New Accounting Standards" in Note 1. In January 2004, Sempra Generation purchased all of the power plant assets of Mesquite Trust for $631 million and extinguished the related debt. The purchase required cash of $268 million and the liquidation of the $363 million in treasury securities held by the Mesquite Trust as collateral.

Termoeléctrica de Mexicali (TDM), a 625-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 TDM and another, unaffiliated Mexicali power 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 finalized its environmental analysis per the court order on December 17, 2004, and is expected to issue a Record of Decision during the second quarter of 2005. The DOE will then determine whether to grant new permits for the cross-border transmission lines. Plaintiffs may elect to dismiss their complaint or to further challenge the agency action. If a stipulation of dismissal is not filed to terminate the litigation by August 15, 2005, the DOE will file a motion by August 22, 2005, showing cause why the court should not set aside the permits. In that event, court hearings may take place in the fourth quarter of 2005. Through December 31, 2004, TDM has made capital expenditures of $343 million.

In October 2002, Sempra Generation purchased the 305-MW, coal-fired Twin Oaks power plant for $120 million. Sempra Generation sells substantially all of the output of the plant under a five-year contract expiring on October 1, 2007. In connection with the acquisition, Sempra Generation also assumed a contract that includes annual commitments to purchase lignite coal for the plant until an aggregate minimum volume has been achieved or through 2025. Note 16 provides additional information on the commitments.

Sempra LNG

In April 2004, Sempra LNG announced plans to develop and construct a $600 million liquefied natural gas (LNG) receiving terminal near Port Arthur, Texas. The terminal would be capable of processing 1.5 billion cubic feet (bcf) of natural gas per day and could be expanded to 3 bcf per day. The company is currently in the process of obtaining FERC approval for the construction of the terminal. The project is expected to begin construction in 2006, with start-up slated for 2009.

In October 2004, Sempra LNG signed a sale and purchase agreement with British Petroleum for the supply of 500 million cubic feet of natural gas per day from Indonesia's Tangguh liquefaction facility to Sempra LNG's Energía Costa Azul regasification terminal. The terminal is expected to cost between $900 million and $1 billion, including related pipeline costs. The 20-year agreement provides for pricing tied to the Southern California border index for natural gas and will supply half the capacity of Energía Costa Azul.

Also in October 2004, Sempra LNG entered into an agreement with Shell International Gas Limited (Shell) by which Shell has contracted to purchase half of the initial capacity of Energía Costa Azul for an initial period of 20 years. This replaces a prior arrangement that contemplated that Shell would have a 50% equity interest in Energía Costa Azul. In December 2004, Sempra LNG entered into two additional contracts: one for the construction of the terminal and one for the construction of the project's breakwater. Note 16 provides additional discussion on commitments related to these contracts.

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 costal zone use permit, were granted in 2003. The permit to construct marine facilities was received in 2004. Construction of Energía Costa Azul began in January 2005.

In January 2005, Sempra LNG was awarded a 15-year natural gas supply contract by Mexico's state-owned electric utility, Comisión Federal de Electricidad (CFE). The contract is estimated at $1.4 billion over its life and supports the CFE's future energy needs in northern Baja California, including the Presidente Juarez power plant in Rosarito, and it is anticipated that it will use natural gas processed at Energía Costa Azul. Starting in 2008 and running through 2022, the agreement provides the CFE with an average of about 130 million cubic feet per day of natural gas.

In April 2003, Sempra LNG completed its acquisition of the proposed Cameron LNG project in Hackberry, Louisiana from a subsidiary of Dynegy, Inc. Sempra LNG paid Dynegy $36 million for the acquisition, which included rights to the location and to the project as it stood in the licensing stage. In 2004, an additional payment of $17 million was made as certain benchmarks and milestones of the project were met. The total cost of the project is expected to be $700 million. The terminal is currently designed to supply 1.5 bcf of natural gas per day. Construction is expected to begin in 2005 and commercial operations are expected to begin in 2008. The FERC approved the construction and operation of the project in September 2003. Cameron LNG is currently seeking from the FERC a modest design change to its marine facilities. In December 2004, Sempra LNG contracted with Norway's Aker Kvaerner and Japan's Ishikawajima-Harima Heavy Industries to build the terminal. The contract is valued at approximately $500 million, but is not yet binding.

Sempra LNG currently leases land in Louisiana for the development of the Cameron terminal. In connection with the purchase of Cameron, Sempra LNG 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. In December 2004, Sempra LNG renewed the terms under the original land lease for another five-year period. Rent payments included in the table of future minimum rental payment obligations in Note 16 are based on the original land lease. Should the terms of the amended lease be triggered, total rent payments and wharfage fees would be $47 million over 30 years.

Sempra Pipelines & Storage

In April 2004, the company acquired land and associated rights for the development of a salt-cavern natural gas storage facility in Evangeline Parish, Louisiana. This facility, operating as the Pine Prairie Energy Center, will consist of three salt caverns with a total capacity of 24 bcf of natural gas. The facility is expected to cost $175 million and to begin operations in 2006. The company is negotiating contracts to sell the capacity of this facility. FERC has issued a certificate of public convenience and necessity for the project and authorized Pine Prairie to charge market-based rates.

In July 2004, the company acquired the rights to develop a salt-cavern natural gas storage facility located in Calcasieu Parish, Louisiana. This facility, operating as Liberty Gas Storage (Liberty), is expected to have capacity of 17 bcf. Liberty is estimated to cost $150 million and to begin operation in 2006.

In 2002, Sempra Pipelines & Storage completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with a TransCanada pipeline that connects to Arizona. Sempra Pipelines & Storage continues to incur costs for the development of a spur line connecting the Energía Costa Azul terminal to Gasoducto Bajanorte and for the expansion of the pipeline. The company has made capital expenditures of $5 million, $7 million and $37 million in the pipeline in 2004, 2003 and 2002, respectively, and a total through December 31, 2004 of $123 million.

Sempra Pipelines & Storage's Mexican subsidiaries build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. In February 2003, Sempra Pipelines & Storage purchased the remaining minority interests in its Mexican subsidiaries. Through December 31, 2004, the distribution companies have made capital expenditures aggregating $142 million. Total capital expenditures for these subsidiaries were $15 million in each of 2004, 2003 and 2002.

These projects are further discussed in Note 16.

NOTE 3. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Investments are generally 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 on the Statements of Consolidated Income in Other Income, Net. 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:

	December 31,	
(Dollars in millions)	**2004**	2003
Equity method investments:		
Chilquinta Energía	**$ 376**	$ 337
Luz del Sur	**157**	177
Sodigas Pampeana and Sodigas Sur	**82**	66
Elk Hills Power	**217**	218
El Dorado Energy	**55**	68
Topaz Power Partners	**66**	—
Housing partnerships	**146**	175
Sempra Financial synthetic-fuel partnerships	**12**	14
Total	**1,111**	1,055
Cost method investments — housing partnerships	**36**	47
Investments in unconsolidated subsidiaries	**1,147**	1,102
Other	**17**	10
Total long-term investments	**$1,164**	$1,112

For equity method investments, costs in excess of equity in net assets (goodwill) were $238 million and $232 million at December 31, 2004 and 2003, 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. 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 APBO 18. Descriptive information concerning each of these investments follows.

Sempra Pipelines & Storage

Sempra Pipelines & Storage and PSEG Global (PSEG), an unaffiliated company, each own a 50-percent interest in Chilquinta Energía S.A., a Chilean electric utility.

On April 1, 2004, Sempra Pipelines & Storage and PSEG sold a portion of their interests in Luz del Sur, a Peruvian electric utility, for a total of $62 million. Each party had a 44-percent interest in Luz del Sur prior to the sale and a 38-percent interest after the sale was completed. As a result of the sale, Sempra Pipelines & Storage recognized a $5 million after-tax gain, which is included in Other Income, Net on the Statements of Consolidated Income.

Sempra Pipelines & Storage also owns 43 percent of two Argentine natural gas utility holding companies, Sodigas Pampeana and Sodigas Sur. As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent declines in the value of the peso, Sempra Pipelines & Storage had reduced the carrying value of its investment downward by a cumulative total of $198 million as of December 31, 2004. 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, Sempra Pipelines & Storage 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, Sempra Pipelines & Storage 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 2006. Sempra Energy also has a $48.5 million political-risk insurance policy under which it has filed a claim to recover a portion of the investments' diminution in value and has commenced the arbitration procedure with the insurance company to determine coverage and the amount of the loss under the policy.

Sempra Generation

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 Sempra Generation 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 Sempra Generation in a joint venture partnership with Reliant Energy Power Generation.

On July 1, 2004, Topaz, a 50/50 joint venture between Sempra Energy Partners and Carlyle/Riverstone, acquired ten Texas power plants from American Electric Power (AEP), including the 632-MW coal-fired Coleto Creek Power Station. Topaz acquired these assets for $430 million in cash and the assumption of various environmental and asset retirement liabilities currently estimated at $50 million. $355 million of the purchase price was provided by non-recourse project financing related solely to the acquisition of the Coleto Creek Power Station. Because of possible revisions to the valuation of the environmental and asset retirement obligations, the allocation of the purchase price remains subject to adjustment until June 30, 2005.

The transaction included the acquisition of six operating power plants with generating capacity of 1,950 MW and four inactive power plants capable of generating 1,863 MW. Concurrently with the acquisition, Topaz sold one of the inactive power plants and no gain or loss was recorded on the transaction. Topaz has entered into several power sales agreements for 572 MW of Coleto Creek Power Station's capacity. As of December 31, 2004, these power sales agreements had a remaining weighted-average life of 4.4 years. Sempra Generation manages the plants.

In conjunction with the acquisition of the plants, Sempra Energy provided AEP a guarantee for certain specified liabilities described in the acquisition agreement. This guarantee is limited to $75 million for the first five years after the acquisition date and $25 million for the next five years, but not more than $75 million over the entire 10-year period. Management does not expect any material losses to result from the guarantee because performance is not expected to be required and, therefore, management believes that the fair value of the guarantee is immaterial.

Sempra Financial

Sempra Financial invests as a limited partner in affordable-housing properties. Sempra Financial'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. Whether Sempra Financial will invest in additional properties will depend on Sempra Energy's income tax position.

On July 1, 2004, Sempra Financial sold its investment in an enterprise that earns Section 29 income tax credits. That investment comprised one-third of Sempra Energy's Section 29 participation, the rest being held by Sempra Commodities, and was sold because the company's alternative minimum tax position defers utilization of the credits in the determination of income taxes currently payable. The transaction has been accounted for under the cost-recovery method, whereby future proceeds in excess of the carrying value of the investment will be recorded as income when they are received. As a result of this sale, Sempra Financial will not be receiving Section 29 income tax credits in the future. Additional discussion of related income tax issues is provided in Note 8.

Sempra Commodities

At December 31, 2004 and 2003, Sempra Commodities had $14 million and $2 million, respectively, of available-for-sale securities included in Other Investments. Purchases of available-for-sale securities were $5 million in 2004. Unrealized gains, net of tax, reported in other comprehensive income were $4 million in 2004. No sales have been recorded since inception.

NOTE 4. DISCONTINUED OPERATIONS

In the first quarter of 2004, Sempra Energy's board of directors approved management's plan to dispose of its interest in AEG, which markets power and natural gas commodities to commercial and residential customers in the United Kingdom. This disposal met the criteria established for recognition as discontinued operations under SFAS 144*, Accounting for the Impairment or Disposal of Long-Lived Assets.* In April 2004, AEG went into administrative receivership and substantially all of the assets were sold. This transaction resulted in an after-tax loss of $2 million in 2004, which has been reported separately on the Statements of Consolidated Income.

The net losses from discontinued operations were $25 million for the year ended December 31, 2004 (including the $2 million loss on disposal). During 2003 and 2002, the company accounted for its investment in AEG under the equity method of accounting. As such, for the years ended December 31, 2003 and 2002, the company recorded its share of AEG's net losses, $5 million and $10 million, respectively, in Other Income, Net on the Statements of Consolidated Income. Additionally, during the fourth quarter of 2003, the company recorded an after-tax charge of $21 million to write down the carrying value of assets at AEG. Effective December 31, 2003, AEG was consolidated as a result of the adoption of FIN 46, as discussed in Note 1.

Included within the net loss from discontinued operations are AEG's operating results, summarized below:

(Dollars in millions)	Year ended December 31, 2004
Operating revenues	$201
Loss from discontinued operations, before income tax benefit of $7	$ (30)
Loss on disposal of discontinued operations, before income tax benefit of $4	$ (6)

AEG's balance sheet data, excluding intercompany balances (which are significant) eliminated in consolidation, are summarized below:

(Dollars in millions)	**December 31, 2004**	December 31, 2003
Assets:		
Accounts receivable	**$37**	$137
Other current assets	**33**	83
Total assets	**$70**	$220
Liabilities:		
Accounts payable	**$—**	$ 36
Other current liabilities	**17**	16
Total liabilities	**$17**	$ 52

NOTE 5. SHORT-TERM BORROWINGS

Committed Lines of Credit

At December 31, 2004, the company had available $4.5 billion in unused, committed lines of credit to provide liquidity and support commercial paper. As of December 31, 2004, $34 million of the lines supported variable-rate debt.

The California Utilities have a combined $500 million three-year syndicated revolving credit facility under which each utility individually may borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement bear interest at rates varying with market rates and the utility's credit rating. The agreement requires each utility to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as defined in the agreement) of no more than 60 percent. Borrowings under the agreement are individual obligations of the borrowing utility and a default by one utility would not constitute a default, or preclude borrowings by, the other. At December 31, 2004, the California Utilities had no amounts outstanding under this facility. SoCalGas had $30 million of commercial paper outstanding as of December 31, 2004.

Sempra Commodities has a two-year syndicated revolving line of credit providing up to $1 billion of extensions of credit (consisting of borrowings, letters of credit and other credit support accommodations) to Sempra Commodities and certain of its affiliates. The agreement expires in 2006. The amount of credit extended on a non-guaranteed basis is limited by the amount of a borrowing base consisting of receivables, inventories and other assets of Sempra Commodities that secure the credit facility and that are valued for purposes of the borrowing base at varying percentages of current market value. Credit utilization above the borrowing base (up to a maximum of $500 million) is guaranteed by Sempra Energy subject to the overall $1 billion credit limit. Non-guaranteed extensions of credit bear interest and fees that vary with Sempra Commodities' tangible net worth, and guaranteed extensions bear interest and fees varying with Sempra Energy's credit ratings. Extensions of credit are subject to the absence of any development or event that has had or would reasonably be expected to have a material adverse effect on Sempra Commodities. The facility also requires Sempra Commodities to meet certain financial tests at the end of each quarter (including current ratio, leverage ratio and minimum consolidated net worth tests) and (while guaranteed borrowings are outstanding) also requires Sempra Energy to meet, at the end of each quarter and as defined in the credit facility, a leverage ratio of consolidated indebtedness to consolidated total capitalization of not more than 65 percent. It also imposes certain other limitations on Sempra Commodities, including limitations on other indebtedness, capital expenditures, liens, transfers of assets, investments, loans, advances, dividends, other distributions, modifications of risk-management policies and transactions with affiliates. At December 31, 2004, outstanding extensions of credit under the facility totaled $489 million, including $439 million in letters of credit and $50 million in borrowings outstanding.

Sempra Global has a $1.5 billion three-year syndicated revolving credit facility that expires in 2007, and a substantially identical $500 million three-year revolving credit facility that expires in 2006. Borrowings under each facility are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit rating. Each facility requires Sempra Energy to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as identically defined in each facility) of no more than 65 percent. Sempra Global had letters of credit of $36 million and $220 million of commercial paper, guaranteed by Sempra Energy, outstanding at December 31, 2004. As of December 31, 2003, Sempra Global had no commercial paper and a letter of credit of $18 million outstanding.

PE has a revolving credit commitment of $500 million that expires in September 2005. Borrowings under the credit agreement are available to provide loans to Sempra Global and would bear interest at rates varying with market rates, PE's credit ratings and amounts borrowed. Borrowings are guaranteed by Sempra Energy and would be subject to mandatory repayment if Sempra Energy's or SoCalGas' ratio of debt to total capitalization (as defined in the agreement) were to exceed 65 percent, or should there be a change in law materially and adversely affecting the ability of SoCalGas to pay dividends or make other distributions to PE. No amounts were outstanding under this facility at December 31, 2004.

Sempra LNG has a $1.25 billion five-year syndicated revolving credit facility that expires in 2009. The $1.25 billion also provides for the issuance of letters of credit not exceeding $200 million outstanding at any one time. Borrowings, letter of credit obligations and other obligations under the facility are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit ratings. The facility requires Sempra Energy to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as defined in the agreement) of no more than 65 percent. Sempra LNG did not have any outstanding borrowings against this line at December 31, 2004.

Uncommitted Lines of Credit

At December 31, 2004, Sempra Commodities had $226 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, 2004, Sempra Commodities had $103 million of letters of credit and $25 million of short-term borrowings outstanding against these lines. At December 31, 2003, Sempra Commodities had letters of credit of $420 million, and no short-term borrowings outstanding.

Other

In addition to the lines of credit, Sempra Energy had $80 million and $28 million of other short-term debt outstanding at December 31, 2004 and 2003, respectively, that was due to parties other than financial institutions. The company's weighted average interest rate on the total short-term debt outstanding was 2.82% and 7.56% at December 31, 2004 and 2003, respectively.

NOTE 6. LONG-TERM DEBT

(Dollars in millions)	December 31, 2004	2003
First mortgage bonds		
Variable rate (2.63% at December 31, 2004) December 1, 2009	**$ 100**	$ —
4.375% January 15, 2011	**100**	100
Variable rates after fixed-to-floating rate swaps (2.69% at December 31, 2004) January 15, 2011	**150**	150
4.8% October 1, 2012	**250**	250
6.8% June 1, 2015	**14**	14
5.45% April 15, 2018	**250**	250
5.9% June 1, 2018	**68**	68
5.9% September 1, 2018	**93**	176
5.85% June 1, 2021	**60**	60
5.25% to 7% December 1, 2027	**150**	225
After floating-to fixed rate swap expiring 2009:		
2.516% to 2.832% January and February 2034	**176**	—
2.8275% May 1, 2039	**75**	—
6.1% September 1, 2019	**—**	35
Variable rates September 1, 2020	**—**	58
6.875% November 1, 2025	**—**	175
	1,486	1,561
Other long-term debt		
5.60% Equity Units May 17, 2007*	**600**	600
7.95% Notes March 1, 2010	**200**	500
Notes at variable rates after fixed-to-floating swap (5.97% at December 31, 2004) March 1, 2010	**300**	—
6.0% Notes February 1, 2013	**400**	400
6.95% Notes December 1, 2005	**300**	300
Notes at variable rates (2.82% at December 31, 2004) May 21, 2008	**300**	—
4.75% Notes May 15, 2009	**300**	—
Rate-reduction bonds, 6.31% to 6.37% at December 31, 2004 payable annually through 2007	**198**	263
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	**76**	110
Employee Stock Ownership Plan		
Bonds at 4.213% November 1, 2014	**82**	82
Bonds at variable rates (3.00% at December 31, 2004) November 1, 2014	**33**	19
5.5% December 1, 2021	**60**	60
5.3% July 1, 2021	**39**	39
4.9% March 1, 2023	**25**	25
6.375% May 14, 2006	**8**	8
5.67% January 18, 2028	**5**	5
Variable rates September 2005	**—**	630
Notes at variable rates after a fixed-to-floating rate swap July 1, 2004	**—**	500
Other debt	**33**	15
Capitalized leases	**6**	8
Market value adjustments for interest rate swaps, net (expiring 2009 — 2011)	**13**	23
	4,594	5,278
Current portion of long-term debt	**(398)**	(1,433)
Unamortized discount on long-term debt	**(4)**	(4)
Total	**$4,192**	$ 3,841

* 4.62% after remarketing in February 2005, as discussed in Note 13.

Excluding capital leases, which are described in Note 16, and market value adjustments for interest-rate swaps, maturities of long-term debt are:

(Dollars in millions)	
2005	$ 398
2006	100
2007	683
2008	308
2009	425
Thereafter	2,661
Total	$4,575

Holders of variable-rate bonds may require the issuer to repurchase them prior to scheduled maturity. However, since repurchased bonds would be remarketed and funds for repurchase are provided by long-term revolving credit agreements (which are generally renewed upon expiration and which are described in Note 5), it is expected that the bonds will be held to the maturities stated above.

Callable Bonds

At the company's option, certain bonds are callable at various dates: $611 million in 2005, $308 million in 2006, $82 million in 2007, and $169 million thereafter.

First Mortgage Bonds

First mortgage bonds are issued by the California Utilities and 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 $3 billion of first mortgage bonds at December 31, 2004.

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

SoCalGas called $175 million of long-term debt in January 2004 and incurred $2 million in call premium costs. This amount has been recorded as a regulatory asset and is being amortized over the life of the original issue.

In December 2004, SoCalGas issued $100 million of first mortgage bonds maturing in 2009. The bonds bear interest at 0.17% above LIBOR.

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, as described in Notes 1 and 2. The debt outstanding of $630 million consisted of notes payable due in 2005. In January 2004, Sempra Generation purchased all of the power plant assets of Mesquite Trust for $631 million and extinguished the related debt. Therefore the liability is classified as short-term at December 31, 2003.

Equity Units

In April and May of 2002, the company publicly offered and issued $600 million of equity units. Additional information on the equity units is provided in Note 13.

Unsecured Long-term Debt

Various long-term obligations totaling $2.8 billion are unsecured at December 31, 2004.

On January 15, 2003, $70 million of SoCalGas' 5.67% $75 million medium-term notes were put back to the company.

In May 2004, the company issued $600 million of senior unsecured notes, consisting of $300 million of 4.75% fixed-rate notes and $300 million of floating-rate notes maturing May 15, 2009 and May 21, 2008, respectively. The proceeds of the issuance were used to repay $500 million of debt maturing July 1, 2004, and for general corporate purposes.

Rate-Reduction Bonds

In December 1997, $658 million of rate-reduction bonds were issued on behalf of SDG&E at an average interest rate of 6.26%. These bonds were issued to facilitate the 10-percent rate reduction mandated by California's electric-restructuring law, which is described in Note 14. 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 Sempra Global's subsidiaries. The Trust is used to fund part of the retirement savings plan described in Note 9. The notes, which mature in 2014, are repriced weekly and subject to repurchase by the company at the holder's option, depending on market demand. ESOP debt was paid down by $13 million during the last three years when approximately 538,000 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 $5 million in 2004, $6 million in 2003 and $7 million in 2002. Dividends used for debt service amounted to $2 million in 2004 and 2003, and $3 million in 2002.

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. In May 2004, Sempra Energy entered into interest-rate swaps which effectively exchanged the fixed rate on $300 million of its $500 million 7.95% notes for a floating rate. The swaps expire in 2010. In September 2004, SDG&E entered into interest-rate swaps to exchange the floating rates on its $251 million Chula Vista Series 2004 bonds for fixed rates. The swaps expire in 2009. In December 2003, SoCalGas entered into an interest-rate swap that effectively exchanged the fixed rate on $150 million of its $250 million 4.375% first mortgage bonds for a floating rate. The swap expires in 2011. The schedule of long-term debt reflects previous interest-rate swaps related to other debt. Accordingly, market value adjustments to long-term debt of $10 million and $19 million were recorded in 2004 and 2003, respectively, to reflect, without affecting net income or other comprehensive income, the unfavorable economic consequences (as measured at December 31, 2004 and 2003) of having entered into the swap transactions.

NOTE 7. FACILITIES UNDER JOINT OWNERSHIP

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

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

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

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

SONGS Decommissioning

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

The company's share of decommissioning costs for the SONGS units is estimated to be $328 million in 2004 dollars. Cost studies are updated every three years, with the next update expected to be submitted to the CPUC for its approval in 2006. Rate recovery of decommissioning costs is allowed until the time that the costs are fully recovered, and is subject to adjustment every three years based on the costs allowed by regulators. Collections are authorized to continue until 2013, at which time sufficient funds are expected to have been collected to fully decommission SONGS, but may be extended by CPUC approval until 2022, when the SONGS' operating license ends and the decommissioning of SONGS Units 2 and 3 would be expected to begin.

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

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled, removed and disposed of. Spent nuclear fuel has been removed from the Unit 1 Spent Fuel Pool and stored on-site in an

Independent Spent Fuel Storage Facility (ISFSI) licensed by the NRC. The remaining major work will include dismantling, removal and disposal of all remaining Unit 1 equipment and facilities (both nuclear and non-nuclear components), and decontamination of the site. These activities are expected to be completed in 2008. The ISFSI and the reactor vessel will remain on site until a permanent storage facility becomes available.

Trust investments include:

(Dollars in millions)	Maturity dates	December 31, 2004	2003
Municipal bonds	2005 — 2034	**$ 45**	$ 47
U.S. government issues	2005 — 2034	**209**	181
Short-term cash and other	2005	**55**	49
Stocks		**303**	293
Total		**$612**	$570

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

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

Discussion regarding the impact of SFAS 143 is provided in Note 1. Additional information regarding SONGS is included in Notes 14 and 16.

NOTE 8. INCOME TAXES

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

	Years ended December 31, 2004	2003	2002
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Utility depreciation	**3.7**	6.7	5.2
State income taxes, net of federal income tax benefit	**3.8**	7.0	7.0
Tax credits	**(13.5)**	(22.6)	(18.5)
Income from unconsolidated foreign subsidiaries	**(4.2)**	(4.3)	(2.0)
Settlement of Internal Revenue Service audit	**—**	(11.2)	(3.6)
Reduction of prior period state income tax accruals, net of federal income tax benefit	**(3.1)**	—	—
Reduction of interest rate on prior period federal income tax liabilities, net of tax	**(1.7)**	—	—
Other, net	**(2.7)**	(4.3)	(2.9)
Effective income tax rate	**17.3%**	6.3%	20.2%

The geographic components of total income from operations before income taxes are as follows:

(Dollars in millions)	Years ended December 31, 2004	2003	2002
Domestic	**$ 796**	$551	$584
Foreign	**317**	191	137
Total income before income taxes	**$1,113**	$742	$721

The components of income tax expense are as follows:

(Dollars in millions)	Years ended December 31, 2004	2003	2002
Current:			
Federal	**$120**	$ 80	$ 220
State	**21**	74	56
Foreign	**39**	11	13
Total	**180**	165	289
Deferred:			
Federal	**17**	(126)	(138)
State	**(24)**	(4)	5
Foreign	**26**	18	(5)
Total	**19**	(112)	(138)
Deferred investment tax credits	**(6)**	(6)	(5)
Total income tax expense	**$193**	$ 47	$ 146

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

(Dollars in millions)	2004	2003
Deferred tax liabilities:		
Differences in financial and tax bases of depreciable and amortizable assets	**$ 861**	$ 891
Balancing accounts and regulatory assets	**124**	239
Unrealized revenue	**79**	63
Partnership income	**56**	34
Loss on reacquired debt	**38**	38
Property taxes	**25**	22
Equity units	**21**	12
Other	**11**	—
Total deferred tax liabilities	**1,215**	1,299
Deferred tax assets:		
General business tax credit carryforward	**193**	152
Credits from alternative minimum tax	**111**	77
Investment tax credits	**55**	61
Net operating losses of foreign entities	**104**	112
Compensation-related items	**173**	134
Postretirement benefits	**51**	31
Other deferred liabilities	**29**	190
State income taxes	**48**	57
Bad debt allowance	**18**	28
Other accruals not yet deductible	**35**	27
Other	**32**	51
Total deferred tax assets	**849**	920
Net deferred income tax liability before valuation allowance	**366**	379
Valuation allowance	**39**	20
Net deferred income tax liability	**$ 405**	$ 399

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

(Dollars in millions)	**2004**	2003
Current (asset) liability	**$ (15)**	$ 31
Noncurrent liability	**420**	368
Total	**$405**	$399

In connection with its affordable-housing investments, the company has $193 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 2024. The company expects to utilize the credits prior to expiration. In addition, the company has $111 million of alternative minimum tax credits with no expiration date. All of these credits have been included in the calculation of income tax expense.

Foreign subsidiaries have $314 million in unused net operating losses available to reduce future income taxes, primarily in Mexico, Canada and the United Kingdom. Significant amounts of these losses become unavailable to reduce future incomes taxes beginning in 2009. Financial statement benefits have been recorded on all but $88 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 $88 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 ($606 million at December 31, 2004), 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.

The company believes it has adequately provided for income tax issues not yet resolved with federal, state and foreign tax authorities. At December 31, 2004, $186 million was accrued for such matters. Although not probable, the most adverse resolution of these issues could result in additional charges to earnings in future periods. Based upon a consideration of all relevant facts and circumstances, the company does not believe the ultimate resolution of tax issues for all open tax periods will have a materially adverse effect upon its results of operations or financial condition.

The new American Jobs Creation Act enables companies to repatriate monies earned outside the U.S. at an income tax cost of only 15 percent of the normal rate. To achieve this reduction, the repatriation must occur by the end of 2005. The company has not completed its analysis and does not expect to be able to make a decision on the amount of such repatriations, if any, until the fourth quarter of 2005. Among other things, the decision will depend on the level of earnings outside the U.S., the debt level between the company's U.S. and non-U.S. affiliates, and administrative guidance from the Internal Revenue Service.

Section 29 Income Tax Credits

On July 1, 2004, Sempra Financial sold its investment in an enterprise that earns Section 29 income tax credits. That investment comprised one-third of Sempra Energy's Section 29 participation and was sold because the company's alternative minimum tax position defers utilization of the credits in the determination of income taxes currently payable. The transaction has been accounted for under the cost-recovery method, whereby future proceeds in excess of the carrying value of the investment will be recorded as income as received. As a result of this sale, Sempra Financial will not be receiving Section 29 income tax credits in the future.

The IRS has conducted various examinations of the partnerships associated with the Section 29 income tax credits, covering various years as recent as 2000, depending on the partnership. It has reported no change in the credits. From acquisition of the facilities in 1998, the company has generated Section 29 income tax credits of $349 million through December 31, 2004, of which $98 million were recorded for the year ended December 31, 2004.

In the next three years, if the annual average wellhead price per barrel of oil reaches a certain price, a phase-out of Section 29 credits will begin. For 2005, 2006 and 2007, those prices are $52.17, $53.21, and $54.27, respectively.

Pacific Enterprises' Quasi-Reorganization

Effective December 31, 1992, PE effected a quasi-reorganization for financial reporting purposes. The reorganization resulted in a restatement of the company's assets and liabilities to their estimated fair value at December 31, 1992 and the elimination of PE's retained earnings deficit. Since the reorganization was for financial purposes and not a taxable transaction, the company established deferred taxes relative to the book and tax bases differences.

During 2004, the company completed an extensive analysis of PE's deferred tax accounts. The analysis resulted in a $72 million reduction of the deferred tax liabilities and an offsetting credit to equity. The credit was recorded to equity because the balances related to tax effects of transactions prior to the quasi-reorganization. In 2004, the company also concluded its outstanding IRS examinations and appeals related to PE and its subsidiaries. As of December 31, 2004, the company's balance sheet includes a net deferred tax asset of $15 million related to remaining reserves arising from the quasi-reorganization.

NOTE 9. 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 either final average or career salary.

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

There were no amendments to the company's pension and other postretirement benefit plans in 2003 or 2004. 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.

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

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2004**	2003	**2004**	2003
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	**$2,578**	$2,290	**$ 954**	$ 797
Service cost	**49**	52	**21**	19
Interest cost	**154**	152	**51**	55
Actuarial loss (gain)	**132**	285	**(64)**	116
Benefit payments	**(219)**	(201)	**(40)**	(33)
Net obligation at December 31	**2,694**	2,578	**922**	954
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	**2,263**	1,984	**519**	409
Actual return on plan assets	**269**	453	**56**	90
Employer contributions	**27**	27	**50**	53
Benefit payments	**(219)**	(201)	**(40)**	(33)
Fair value of plan assets at December 31	**2,340**	2,263	**585**	519
Benefit obligation, net of plan assets at December 31	**(354)**	(315)	**(337)**	(435)
Unrecognized net actuarial loss	**278**	273	**221**	317
Unrecognized prior service cost	**74**	83	**(13)**	(13)
Unrecognized net transition obligation	**—**	1	**—**	—
Net recorded asset (liability) at December 31	**$ (2)**	$ 42	**$(129)**	$(131)

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

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2004**	2003	**2004**	2003
Prepaid benefit cost	**$ 147**	$ 178	**$ —**	$ —
Accrued benefit cost	**(149)**	(136)	**(129)**	(131)
Additional minimum liability	**(131)**	(118)	**—**	—
Intangible asset	**7**	9	**—**	—
Regulatory asset	**62**	—	**—**	—
Accumulated other comprehensive income (pretax)	**62**	109	**—**	—
Net recorded asset (liability)	**$ (2)**	$ 42	**$(129)**	$(131)

The accumulated benefit obligation for defined benefit pension plans was $2.5 billion and $2.4 billion at December 31, 2004 and 2003, respectively. The following table provides information concerning pension plans with benefit obligations in excess of plan assets as of December 31.

	Projected Benefit Obligation Exceeds the Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	
(Dollars in millions)	**2004**	2003	**2004**	2003
Projected benefit obligation	**$2,290**	$2,189	**$694**	$662
Accumulated benefit obligation	**$2,076**	$1,994	**$692**	$661
Fair value of plan assets	**$2,085**	$2,012	**$569**	$538

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

(Dollars in millions)	Pension Benefits 2004	Pension Benefits 2003	Pension Benefits 2002	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
Service cost	**$ 49**	$ 52	$ 57	**$ 21**	$ 19	$ 13
Interest cost	**154**	152	149	**51**	55	42
Expected return on assets	**(154)**	(161)	(204)	**(36)**	(35)	(39)
Amortization of:						
Transition obligation	**—**	1	1	—	9	9
Prior service cost	**9**	9	7	(1)	(1)	(1)
Actuarial (gain) loss	**12**	9	(18)	10	10	—
Regulatory adjustment	**(116)**	(14)	32	**2**	(4)	25
Total net periodic benefit cost (income)	**$ (46)**	$ 48	$ 24	**$ 47**	$ 53	$ 49

As described in Note 1, the company adopted FSP 106-2 in 2004 retroactive to the beginning of the year. The company and its actuarial advisors determined that benefits provided to certain participants will actuarially be at least equivalent to Medicare Part D, and, accordingly, the company will be entitled to an expected tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2004 by $102 million and the net postretirement benefit cost for 2004 by $13 million.

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

	Pension Benefits 2004	Pension Benefits 2003	Other Postretirement Benefits 2004	Other Postretirement Benefits 2003
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	**5.66%**	6.00%	**5.66%**	6.00%
Rate of compensation increase	**4.50%**	4.50%	**4.50%**	4.50%
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31:				
Discount rate	**6.00%**	6.50%	**6.00%**	6.50%
Expected return on plan assets	**7.50%**	7.50%	**7.32%**	7.30%
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.

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

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

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	$ 10
Effect on the health-care component of the accumulated other postretirement benefit obligation	$134	$106

Pension Plan Investment Strategy

The asset allocation for the company's pension trust (which includes other postretirement benefit plans, except for those of the California Utilities separately described below) at December 31, 2004 and 2003 and the target allocation for 2005 by asset categories are as follows:

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

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

Investment Strategy for SoCalGas' Other Postretirement Benefit Plans

The asset allocation for SoCalGas' other postretirement benefit plans at December 31, 2004 and 2003 and the target allocation for 2005 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2005	**2004**	2003
U.S. Equity	70%	**73%**	71%
Fixed Income	30	**27**	27
Cash	0	**0**	2
Total	100%	**100%**	100%

SoCalGas' other postretirement benefit plans, which are distinct from other postretirement benefit plans included in the company's pension trust (shown 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. These plans are managed using index funds.

Investment Strategy for SDG&E's Postretirement Health Plans

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

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

SDG&E's postretirement health plans, which also are distinct from other postretirement benefit plans included in the company's pension trust (shown above), pay premiums to the health maintenance organization and point-of-service plans from company and participant contributions. SDG&E'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 $34 million to the pension plans and $58 million to the other postretirement benefit plans in 2005.

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

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2005	$ 175	$ 42
2006	$ 194	$ 45
2007	$ 190	$ 48
2008	$ 200	$ 50
2009	$ 208	$ 52
2010 — 2014	$1,168	$295

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

(Dollars in millions)	
2005	$—
2006	$ 3
2007	$ 3
2008	$ 4
2009	$ 4
2010 — 2014	$24

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 had been required to remain so invested until termination of employment or until the employee's attainment of age 55, when they could be transitioned into other investments. Effective January 1, 2005, all employees have the ability to transfer employer contributions into other investments. The employees' contributions are invested in company stock, mutual funds, institutional trusts or guaranteed investment contracts (the same investments in which employees may now direct the employer contributions). The plans of certain non-wholly owned subsidiaries prohibit investments in stock of the company. 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 $25 million in 2004, $22 million in 2003 and $20 million in 2002. The market value of company stock held by the savings plans was $801 million and $675 million at December 31, 2004 and 2003, respectively.

Sempra Commodities also operates defined contribution plans outside of the United States. The contributions made by the company to such plans were $3 million, $3 million and $2 million in 2004, 2003 and 2002, respectively.

Employee Stock Ownership Plan

All contributions to the ESOP Trust (described in Note 6) 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 2.1 million shares and 2.4 million shares, respectively, of Sempra Energy common stock, with fair values of $78.7 million and $71.6 million, at December 31, 2004 and 2003, respectively.

NOTE 10. 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 2004, 2003 and 2002, 1,223,000, 1,359,500, and 544,100 shares of restricted company stock, respectively, were awarded to key employees. Compensation expense for the issuance of the restricted stock was $37 million in 2004, $16 million in 2003 and $7 million in 2002. The corresponding weighted average market values per share at the time of grant were $30.57, $24.42 and $24.77, respectively. Subject to earlier forfeitures upon termination of employment, the 2004 and 2003 awards are scheduled to vest at the end of four years if performance-based goals are satisfied, except in the event of a change in control or in certain cases where employment agreements provide alternate methods of vesting. The 2002 award is scheduled to vest at the end of seven years, but is also subject to earlier vesting over a four-year period upon satisfaction of objective performance-based goals. Holders of restricted stock have full voting rights. They also have full dividend rights, except for senior officers, whose dividends are reinvested to purchase additional shares that become subject to the same performance-based vesting conditions as the restricted stock to which they relate.

In 2004, 2003 and 2002, the company granted to directors, officers and key employees options to acquire 1,389,000, 1,848,000 and 3,444,300 shares of stock, respectively. The option prices were equal to the market price of common stock at the dates of grant. The officers' and key employees' options vest over four-year periods (sooner in the event of a change in control or in certain cases of employment agreements) 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 2001 as discussed below) and similar awards was $4 million, $6 million and ($2 million) in 2004, 2003 and 2002, respectively.

The plans permit the granting of dividend equivalents with the stock option grants. For such grants, all of which are now fully vested, recipients receive dividends during the period they hold the options.

As of December 31, 2004, 14,358,630 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 equal to 1.5 percent of the outstanding shares of Sempra Energy common stock become available for grant.

In 1995, SFAS 123 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 APBO 25. Discussion of SFAS 123R (a revision of SFAS 123) is provided in Note 1.

STOCK OPTION ACTIVITY

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITH DIVIDEND EQUIVALENTS			
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
Exercised	**(286,539)**	**$21.04**	
December 31, 2004	**362,511**	**$22.44**	**362,511**

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITHOUT DIVIDEND EQUIVALENTS			
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
Granted	**1,389,000**	**$30.33**	
Exercised	**(3,837,541)**	**$20.96**	
Cancelled	**(73,110)**	**$25.79**	
December 31, 2004	**12,712,206**	**$24.06**	**7,771,556**

Additional information on options outstanding at December 31, 2004, is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Remaining Life	Weighted Average Exercise Price
Outstanding Options			
$ 16.87 - $ 21.00	2,797,522	4.55	$20.08
$ 22.50 - $ 25.20	7,663,183	6.80	$23.90
$ 26.31 - $ 35.73	2,614,012	6.51	$28.54
	13,074,717	6.26	$24.01
Exercisable Options			
$ 16.87 - $ 21.00	2,769,397		$20.09
$ 22.50 - $ 25.20	4,120,658		$23.66
$ 26.31 - $ 35.73	1,244,012		$26.50
	8,134,067		$22.88

The grant-date fair value of each option grant (including dividend equivalents where applicable) was estimated using a modified Black-Scholes option-pricing model. Weighted average grant-date fair values for options granted in 2004, 2003 and 2002 were $6.32, $4.31 and $4.45, respectively.

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

	2004	2003	2002
Stock price volatility	**25%**	25%	22%
Risk-free rate of return	**3.7%**	3.4%	4.8%
Annual dividend yield	**3.3%**	4.1%	4.1%
Expected life	**6 Years**	6 Years	6 Years

NOTE 11. 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, debt related to Mesquite Power 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:

	2004		2003	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in limited partnerships	**$ 194**	**$ 262**	$ 236	$ 352
First mortgage bonds	**$1,486**	**$1,521**	$1,561	$1,578
Notes payable	**1,800**	**1,876**	1,700	1,842
Equity units	**600**	**747**	600	680
SDG&E rate-reduction bonds	**198**	**241**	263	284
Debt incurred to acquire limited partnerships	**76**	**87**	110	128
Long-term debt	**434**	**451**	414	436
Total long-term debt	**$4,594**	**$4,923**	$4,648	$4,948
Due to unconsolidated affiliates	**$ 362***	**$ 383**	$ 362*	$ 392
Preferred stock of subsidiaries	**$ 200****	**$ 186**	$ 203**	$ 184

* Includes $200 million of mandatorily redeemable trust preferred securities.

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

The fair values of investments in limited partnerships were based on the present value of estimated future 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 and mandatorily redeemable trust preferred securities are based on their quoted market prices or quoted market prices for similar securities.

Accounting for Derivative Instruments and Hedging Activities

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

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change (favorable impacts of $68 million in 2004 and $16 million in 2003 related to fair value hedges, and unfavorable impacts of $3 million in 2004 and $1 million in 2003 related to cash flow hedges) together with the offsetting gain or loss on the hedged item attributable to the risk being hedged; therefore, there is no effect on net income. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is similarly reflected. The ineffective portion is reported in earnings immediately. The effect on other comprehensive income for the years ended December 31, 2004 and 2003 was $36 million and

$3 million, respectively, all related to cash flow hedges. The balance in Accumulated Other Comprehensive Income at December 31, 2004 related to cash flow hedges was $39 million. In instances where derivatives do not qualify for hedge accounting, gains and losses are recorded in earnings immediately.

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 by the company and, in the case of the California Utilities, the prices to be charged to their customers. At the California Utilities, the use of derivative financial instruments is subject to certain limitations imposed by company policy and regulatory requirements. The company classifies its forward contracts as follows:

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

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

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

(Dollars in millions)	**2004**	2003
Fixed-price Contracts and Other Derivatives:		
Current liabilities	**$157**	$148
Noncurrent liabilities	**500**	680
Total liabilities	**657**	828
Other current assets	**8**	26
Sundry assets	**14**	—
Total assets	**22**	26
Net liabilities	**$635**	$802

Regulatory assets and liabilities related to derivatives held by the California Utilities at December 31 were:

(Dollars in millions)	**2004**	2003
Regulatory Assets and Liabilities:		
Current regulatory assets	**$152**	$144
Other regulatory assets	**500**	650
Total	**652**	794
Current regulatory liabilities	**4**	1
Net regulatory assets	**$648**	$793

As of December 31, 2004, the difference between net liabilities and net regulatory assets ($13 million) was due to market value adjustments related to fixed-to-floating interest-rate swaps. As of December 31, 2003, the difference between net liabilities and net regulatory assets ($9 million) 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.

Pre-tax income from transactions associated with fixed-price contracts and other derivatives included $13 million of income in 2004 recorded in Other Income, Net and $2 million of losses in 2003 recorded in Operating Revenues in the Statements of Consolidated Income.

Market Risk

The company's policy is to use derivative physical and financial 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 credit-worthy. The use of these instruments exposes the company to market and credit risk, which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated.

Interest-Rate Risk Management

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower the overall cost of borrowing. This is described in Note 6.

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 Commodities

Sempra Commodities 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 asked 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. Sempra Commodities 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 Sempra Commodities. Sempra Energy guarantees many of Sempra Commodities' transactions.

Sempra Commodities also derives a 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 for all activities are recorded by Sempra Commodities 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 trading 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 (discussed in 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 43. Note 2 discusses Sempra Commodities' 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.

The carrying values of trading assets and trading liabilities, primarily at Sempra Commodities, approximate the following:

	December 31,	
(Dollars in millions)	**2004**	2003
TRADING ASSETS		
Trading-related receivables and deposits, net:		
Due from trading counterparties	**$2,371**	$2,215
Due from commodity clearing organizations and clearing brokers	**235**	135
	2,606	2,350
Derivative trading instruments:		
Unrealized gains on swaps and forwards	**1,607**	1,148
OTC commodity options purchased	**732**	459
	2,339	1,607
Commodities owned	**1,547**	1,420
Total trading assets	**$6,492**	$5,377
TRADING LIABILITIES		
Trading-related payables	**$3,182**	$2,255
Derivative trading instruments sold, not yet purchased:		
Unrealized losses on swaps and forwards	**1,232**	1,114
OTC commodity options written	**252**	226
	1,484	1,340
Commodities sold with agreement to repurchase	**513**	922
Total trading liabilities	**$5,179**	$4,517

Based on quarterly measurements, the average fair values during 2004 for trading assets and liabilities approximate $5.7 billion and $4.6 billion, respectively. For 2003, the amounts were $5.1 billion and $4.4 billion, respectively.

At Sempra Commodities, market risk from market making and trading activities 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 electric and natural gas delivery contract activity from fluctuations in natural gas or electricity prices is reduced by Sempra Commodities' hedging strategy as described above.

Sempra Commodities' credit risk from physical and financial instruments as of December 31, 2004 is represented by their positive fair value after consideration of collateral. Options written do not expose Sempra Commodities 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. Credit risk is also associated with its retail customers.

The following table summarizes the counterparty credit quality and exposure for Sempra Commodities at December 31, 2004 and 2003, 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 $1.1 billion and $569 million at December 31, 2004 and 2003, respectively.

	December 31,	
(Dollars in millions)	**2004**	2003
Counterparty credit quality*		
Commodity exchanges	**$ 235**	$ 135
AAA	**7**	5
AA	**259**	316
A	**562**	484
BBB	**680**	371
Below investment grade and not rated	**532**	417
Total	**$2,275**	$1,728

* As determined by rating agencies or internal models intended to approximate rating-agency determinations.

NOTE 12. PREFERRED STOCK OF SUBSIDIARIES

(in millions)	Call/ Redemption Price	December 31, 2004	2003
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, 850,000 and 950,000 shares outstanding at December 31, 2004 and December 31, 2003, respectively	$ 25.00	**21***	24*
Total preferred stock		**$200**	$203

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

PE preferred stock is callable at the applicable redemption price of 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, plus any 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, 2004. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share per year from 2005 to 2007; all remaining shares must be redeemed in 2008. On January 15, 2005, SDG&E redeemed 100,000 shares.

NOTE 13. SHAREHOLDERS' EQUITY AND EARNINGS PER SHARE (EPS)

The following table provides the per share computations for income from continuing operations for the year ended December 31, 2004:

	Income (millions) (numerator)	Shares (thousands) (denominator)	Per Share Amounts
Basic EPS—income from continuing operations	$920	228,271	$ 4.03
Effect of dilutive securities:			
Stock options and restricted stock awards		3,595	(0.06)
Equity Units		1,986	(0.04)
Diluted EPS—income from continuing operations	$920	233,852	$ 3.93

The only difference between basic and diluted earnings per share in 2003 and 2002 was the effect of common stock options. For 2003 and 2002, the effect of dilutive options was equivalent to an additional 2,742,000 and 1,059,000 shares, respectively. The dilution from common stock options is based on 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 an average of 0.1 million and 6.0 million shares for 2003 and 2002, respectively, for which the exercise price was greater than the average market price for common stock during the respective year. In 2004, there were no such options. The company's equity units, described below, had no dilutive effect in 2003 or 2002.

The dilution from unvested restricted stock awards is based on the treasury stock method, whereby assumed proceeds equivalent to the unearned compensation related to the awards are assumed to be used to repurchase shares on the open market at the average market price for the year. In 2003 and 2002, there were restricted awards representing an average of 1.3 million and 0.7 million shares, respectively, that did not affect the calculation since their grant price was greater than the average market price for common stock during the respective year. In 2004 there were no such awards.

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:

	2004	2003	2002
Common shares outstanding, January 1	**226,598,619**	204,911,572	204,475,362
Public issuance	**—**	16,500,000	—
Savings plan issuance*	**1,638,581**	1,436,526	—
Shares released from ESOP	**236,620**	170,613	130,486
Stock options exercised	**4,124,080**	1,926,590	395,788
Restricted stock	**1,223,000**	1,359,500	544,100
Common stock investment plan**	**611,259**	728,241	212,411
Shares repurchased	**(181,819)**	(262,286)	(818,639)
Shares forfeited and other	**(74,360)**	(172,137)	(27,936)
Common shares outstanding, December 31	**234,175,980**	226,598,619	204,911,572

* Prior to 2003, the plan purchased shares in the open market to cover the company's contributions to the savings plan.

** 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, 2004, SDG&E and SoCalGas could have provided a total of $160 million and $200 million, respectively, to Sempra Energy, through dividends and loans.

Equity Units

In 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-average market price). The number of shares to be issued ranges from 20 million to 24 million. The equity units are included in Long-Term Debt on the Consolidated Balance Sheets. Through December 31, 2004, $55 million had been charged to the common stock account in connection with the transaction. In February 2005, the company remarketed the senior notes for their remaining term at a rate of 4.62%.

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 14. ELECTRIC INDUSTRY REGULATION

Background

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

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

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

Department of Water Resources

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

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

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

Power Procurement and Resource Planning

In 2001, the CPUC directed the IOUs to resume electric commodity procurement to cover their net short energy requirements by January 1, 2003 and also implemented legislation regarding procurement and renewables portfolio standards. In addition, the CPUC established a process for review and approval of the utilities' long-term resource and procurement plans, which is intended to identify forecasted needs for generation and transmission resources within a utility's service territory to support transmission grid reliability and to serve customers. An updated 10-year resource plan was approved by the CPUC in December 2004, in a proceeding to consider utility resource planning, including energy efficiency, contracted power, demand response, qualifying facilities, renewable generation and distributed generation. SDG&E's updated long-term resource plan incorporates the resources approved by the CPUC that are discussed below, and recognizes updated CPUC goals to reach a 20-percent renewable resources target by 2010. The updated plan recommends a 500-kV transmission line addition in 2010, which would be processed for approval in a subsequent CPUC proceeding. The CPUC also endorsed SDG&E's continued analysis and planning for a 500-kV transmission line, adopted SDG&E's proposal for cost recovery related to utility-owned generation, recognized the debt-equivalent impact associated with long-term power purchase contracts, adopted a greenhouse gas adder for assessing new resource acquisitions, and established a cap on initial costs for new utility-owned generation resources to level the playing field with respect to power purchase options. The estimated capital cost related to this updated plan is $700 million, to be spent by 2007, for capital projects approved by the CPUC in June 2004, as described below.

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

SONGS

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

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

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

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

Spent Nuclear Fuel

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

NOTE 15. OTHER REGULATORY MATTERS

Natural Gas Industry Restructuring (GIR)

In December 2001, the CPUC issued a decision related to GIR, with implementation anticipated during 2002. On April 1, 2004, after many delays and changes, the CPUC issued a decision that adopts tariffs to implement the 2001 decision. However, by that same decision, the CPUC stayed implementation of the GIR tariffs until it issues a decision in Phase I of the Natural Gas Market Order Instituting Ratemaking (OIR) discussed below. At that time, the CPUC will reconcile the GIR market structure with whatever structure results from the Phase I decision of the Natural Gas Market OIR. If implemented, the stayed decision would unbundle the costs of SoCalGas' backbone transmission system from rates and result in revising noncore balancing account treatment to exclude the balancing of SoCalGas' backbone transmission costs and place SoCalGas at risk for recovery of $80 million for transmission and $81 million for storage (current dollars). The decision would create firm tradable rights for the transmission system. Other noncore costs/revenues would continue to be fully balanced until the decision in the next Biennial Cost Allocation Proceeding (BCAP) discussed below.

Natural Gas Market OIR

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

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

The California Utilities also proposed a methodology and framework to be used by the CPUC for granting pre-approval of new interstate transportation agreements. The Phase I decision approved the California Utilities' transportation capacity pre-approval procedures with some modifications. SoCalGas' existing pipeline capacity contracts with Transwestern Pipeline Company expire in November 2005 and its primary contracts with El Paso Natural Gas Company (El Paso) expire in August 2006. SoCalGas recently was granted pre-approval by the CPUC of a contract for released capacity on the Kern River Gas Transmission Company system, and four capacity contracts with El Paso. The contracts would expire between 2007 and 2011. In January 2005, SDG&E was granted pre-approval of a capacity contract with El Paso that would expire in 2007. In February 2005, SoCalGas filed for pre-approval of two new capacity contracts with Transwestern that would expire in 2009 and 2011. The CPUC's decision on pre-approval of the Transwestern contracts is expected to be received by March 2005. All interstate transportation capacity under the pre-approved contracts will be used to transport natural gas supplies on behalf of the California Utilities' core residential and small commercial customers, and all costs of the capacity will be recovered in the customers' rates through each utility's Purchased Gas Account, a balancing account. In December 2004, pursuant to the Phase I decision, SoCalGas filed an application to implement proposals for transmission system integration, firm access rights, and off-system delivery services. The CPUC has determined that the ratemaking treatment and cost responsibility for any access-related infrastructure will be addressed in future applications to be filed when more is known about the particular projects. Phase II of the Gas Market OIR will review the CPUC's ratemaking policies on throughput risk to better align these with its objectives of promoting energy conservation and adequate infrastructure. Phase II will also investigate the need for emergency natural gas storage reserves and the role of the utility in backstopping the noncore market.

Cost of Service

On December 2, 2004, the CPUC issued a decision in the California Utilities' cost of service proceedings that essentially approved settlements recommended by most major parties to the proceedings. The decision reduces the California Utilities' annual rate revenues, effective retroactively to January 1, 2004, by an aggregate net amount of approximately $56 million from the rates in effect during 2003. The reduced rates will remain in effect through 2007, subject to annual attrition allowances. Of the reduction, $10 million relates to what SDG&E believes to be a computational error concerning its nuclear electric rate revenues. With respect to the $10 million reduction, a Petition for Modification and an Application for Rehearing were filed in December 2004 and January 2005, respectively.

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

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

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

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

Performance-Based Regulation

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

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

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

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

PBR, DSM and Gas Cost Incentive Mechanism (GCIM) rewards are not included in the company's earnings before CPUC approval is received. The only incentive rewards approved during 2004 consisted of $6.3 million related to SoCalGas' Year 9 GCIM, which was approved in February 2004, and $1.5 million related to SDG&E's Year 10 natural gas PBR, which was approved in August 2004. These rewards were awarded by the CPUC subject to refund based on the outcome of the Border Price Investigation discussed below. The cumulative amount of rewards subject to refund based on the outcome of the Border Price Investigation is $65.3 million, substantially all of which has been included in net income in 2004 or previously.

On December 30, 2004, a joint settlement agreement between the California Utilities and the ORA (collectively, the joint parties) was filed with the CPUC for approval. The settlement agreement resolves all outstanding shareholder earnings claims filed with the CPUC commencing in 2000 and those claims that would have been filed through 2007 and 2009, respectively, for SDG&E and SoCalGas, associated with DSM, energy efficiency and low-income energy efficiency programs. The proposed settlement is for $73 million and $14 million, respectively, for SDG&E and SoCalGas (including interest, franchise fees, uncollectible amounts and awards earned in prior years that had not yet then been requested). The joint parties requested expeditious approval of the settlement agreement, without modification. A CPUC decision is expected by the end of the second quarter of 2005.

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

Program	SoCalGas	SDG&E	Total
2003 Distribution PBR	$ —	$8.2	$ 8.2
GCIM/natural gas PBR	2.4	.2	2.6
2003 safety	.5	—	.5
Total	$2.9	$8.4	$11.3

Cost of Capital

Effective January 1, 2005, SDG&E's authorized return on ratebase (ROR) and ROE became 8.18 percent and 10.37 percent, respectively, for its electric distribution and natural gas businesses, down from 8.77 percent and 10.9 percent, respectively. The decrease is a result of the CPUC's automatic triggering mechanism, which resets these rates whenever Moody's Aa utility bond yield as published by Mergent Bond Record changes by more than a specified amount. The current benchmark is 6.19 percent and an automatic adjustment would be triggered if the Mergent Aa utility bond yield were to average less than 5.19 percent or greater than 7.19 percent during the April — September timeframe of any year. The effect of the 2004 changes in ROR and ROE will be to decrease net income in 2005 by $10 million from what it would have been if the 2005 rates had not changed from the 2004 rates. In December 2004, the CPUC ordered SDG&E to file a cost of capital application in 2005 to take effect

January 1, 2006. SDG&E had recommended that the CPUC approve a policy allowing utilities to increase the equity in their authorized capital structure to adjust for the debt equivalent effect of purchased power agreements. The CPUC has directed that such adjustment only be considered in the context of a full review of the cost of capital. The electric-transmission cost of capital is determined under a FERC proceeding and is currently at an 11.25% ROE.

Effective January 1, 2003, SoCalGas' authorized ROE is 10.82 percent and its ROR is 8.68 percent. These rates are subject to automatic adjustment if the 12-month trailing average of 30-year Treasury bond rates and the Global Insight forecast of the 30-year Treasury bond rate 12 months ahead vary by greater than 150 basis points from a benchmark, which is currently 5.38 percent. The 12-month trailing average was 5.03 percent and the Global Insight forecast was 5.44 percent at December 31, 2004.

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

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 sales volumes as compared to the forecasts previously used in establishing transportation rates. The California Utilities filed with the CPUC their 2005 BCAP applications in September 2003, requesting updated transportation rates effective January 1, 2005. In November 2003, an Assigned Commissioner Ruling stayed the BCAP applications until a decision is issued in the GIR implementation proceeding. As a result of the April 1, 2004 decision on GIR implementation as described in Natural Gas Industry Restructuring above, in May 2004 the ALJ in the 2005 BCAP issued a decision dismissing the BCAP applications. The California Utilities are required to file new BCAP applications after the stay in the GIR implementation proceeding is lifted. As a result of the deferrals and the significant decline forecasted in noncore gas throughput on SoCalGas' system, in December 2002 the CPUC issued a decision approving 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 in the Natural Gas OIR proceeding.

CPUC Investigation of Energy-Utility Holding Companies

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

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

CPUC Investigation of Compliance With Affiliate Rules

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

Recovery of Certain Disallowed Transmission Costs

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

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

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

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

Southern California Wildfires

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

Gain on Sale Rulemaking

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

NOTE 16. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The California Utilities buy natural gas under short-term and long-term contracts. 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. Note 15 discusses the CPUC Gas Market OIR.

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

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

(Dollars in millions)	Storage and Transportation	Natural Gas	Total
2005	$202	$ 897	$1,099
2006	123	179	302
2007	21	158	179
2008	20	3	23
2009	16	2	18
Thereafter	189	—	189
Total minimum payments	$571	$1,239	$1,810

Total payments under natural gas contracts were $2.8 billion in 2004, $2.2 billion in 2003 and $1.4 billion in 2002.

In October 2004, Sempra LNG signed a sale and purchase agreement with British Petroleum for the supply of 500 million cubic feet of natural gas per day from Indonesia's Tangguh liquefaction facility to Sempra LNG's Energía Costa Azul regasification terminal. The 20-year agreement provides for pricing tied to the Southern California border index for natural gas and will supply half of the capacity of Energía Costa Azul.

Purchased-Power Contracts

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

Sempra Commodities is committed to purchasing $199 million of power from an unconsolidated affiliate in varying amounts through 2014.

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

(Dollars in millions)	
2005	$ 256
2006	279
2007	313
2008	358
2009	343
Thereafter	4,035
Total minimum payments	$5,584

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Excluding DWR-allocated contracts, total payments under the contracts were $329 million in 2004, $396 million in 2003 and $235 million in 2002.

Coal Commitments

In October 2002, Sempra Generation acquired the 305-MW Twin Oaks Power plant. In connection with the acquisition, Sempra Generation assumed a contract that includes annual commitments to purchase lignite coal either until an aggregate minimum volume has been achieved or through 2025. As of December 31, 2004, Sempra Generation’s future minimum payments under the lignite coal agreement totaled $425 million, for which payments of $31 million are due for 2005, $28 million for 2006, $27 million for 2007, $27 million for 2008, $27 million for 2009 and $285 million thereafter. The minimum payments have been adjusted for allowed shortfalls and 90-percent minimum take-or-pay requirements under the contract.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2005 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2 percent to 5 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company. The company also has long-term capital leases on real property. Property, plant and equipment included $28 million at December 31, 2004 and $36 million at December 31, 2003, related to these leases. The associated accumulated amortization was $24 million and $23 million, respectively.

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

(Dollars in millions)	Operating Leases	Capitalized Leases
2005	$107	$ 2
2006	97	1
2007	93	1
2008	84	1
2009	82	—
Thereafter	178	1
Total future rental commitments	$641	6
Imputed interest (6% to 10%)		(1)
Net commitments		$ 5

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 $30 million at December 31, 2004. These leases are included in the above table at the amounts provided in the lease.

Rent expense for operating leases totaled $88 million in 2004, $90 million in 2003 and $81 million in 2002. Depreciation expense for capitalized leases is included in Depreciation and Amortization on the Statements of Consolidated Income.

Construction Projects

Sempra 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 commitments related to the projects developed or under development, the background of which is provided in Note 2.

Sempra Generation

Sempra Generation is primarily in the business of acquiring, developing and operating power plants throughout the U.S. and Mexico. As of the end of 2004, Sempra Generation had eleven power plants in operation, including eight that are 50% owned.

Sempra Generation has a long-term service agreement expiring in 2023 for maintenance of the turbines at the Mesquite power plant. As of December 31, 2004, commitments under this agreement totaled $264 million, including amounts due of $14 million in 2005, $14 million in 2006, $15 million in 2007, $15 million in 2008, $15 million in 2009 and $191 million thereafter.

Transportation of TDM’s natural gas from Ehrenberg, Arizona to the interconnection with Gasoducto Bajanorte is being provided under an agreement with an unrelated party. Under the agreement, Sempra Generation is obligated to pay a monthly reservation charge for the transport of certain quantities until 2022. The future commitments related to this contract are $79 million. Sempra Generation also has a 20-year agreement expiring in 2023 for maintenance of the turbines at TDM. As of December 31, 2004, commitments under this agreement totaled $83 million, including amounts due of $6 million in 2005, $6 million in 2006, $7 million in 2007, $7 million in 2008, $7 million in 2009 and $50 million thereafter.

Sempra Generation also has commitments for general contracting work at Palomar totaling $99 million as of December 31, 2004. It expects to pay $94 million in 2005 and $5 million in 2006.

Sempra Generation continues to investigate opportunities for new projects, either independently or with unrelated parties. The success of these investigations cannot be predicted. As of December 31, 2004, Sempra Generation has no other significant construction commitments.

Sempra LNG

Sempra LNG develops, builds and operates LNG receipt terminals and will be supplying gas to CFE.

In December 2004, Sempra LNG entered into an agreement with a group of companies for the construction of the Energía Costa Azul LNG receipt facility. The companies included Techint SA de CV, Black & Veatch, Mitsubishi Heavy Industries and Vinci Construction Grands Projects. As of December 31, 2004, expected payments under this contract include $196 million in 2005, $191 million in 2006 and $95 million in 2007, for a total of $482 million over the term of the contract. Also in December 2004, a joint venture involving the Costain Group PLC and China Harbour was awarded a construction contract for the project's breakwater. As of December 31, 2004, Sempra LNG expects to make payments under this contract of $161 million, including $58 million in 2005, $81 million in 2006, $14 million in 2007 and $8 million in 2008.

Sempra Pipelines & Storage

In 2002, Sempra Pipelines & Storage completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with the TransCanada pipeline 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 Sempra Generation's TDM power plant discussed above. Capacity on the pipeline is over 90 percent subscribed. The company had no other commitments for this pipeline at December 31, 2004.

If Sempra Pipelines & Storage proceeds with development of its Liberty project, it will pay the prior owner of its development rights $2 million upon receipt of the related FERC permit and seven percent of the project's revenues over the first five years of operations. A liability instrument will be recorded for these earn-out provisions if and when the company completes its feasibility studies and decides to proceed with this investment.

Guarantees

As of December 31, 2004, substantially all of the company's guarantees were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries. Significant other guarantees are the $25 million related to debt issued by Chilquinta Energía Finance Co., LLC, an unconsolidated affiliate, and the mandatorily redeemable trust preferred securities, which were redeemed in February 2005.

In conjunction with the acquisition of the former AEP power plants, Sempra Energy provided AEP a guarantee for certain specified liabilities described in the acquisition agreement. Note 3 provides additional discussion related to the guarantee.

Sempra Generation's Contract with the DWR

In May 2001, Sempra Generation entered into a ten-year agreement with the DWR to supply up to 1,900 MW of power to California. Sempra Generation may, but is not obligated to, deliver this electricity from its portfolio of natural gas-fired plants in the western United States and Baja California, Mexico. If and when Sempra Generation uses these plants to supply the entire 1,900 MW, those sales would comprise more than two-thirds of the plants' capacity. 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. Based on current natural gas prices, the price of power under the long-term contracts exceeds the current spot market price for electricity. Information concerning the validity of this contract, the FERC's orders upholding this contract and the pending appeal is provided under "Legal Proceedings — DWR Contract" below.

Environmental Issues

The company's operations are subject to federal, state and local environmental laws and regulations governing hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. Most of the environmental issues faced by the company have occurred at the California Utilities. However, now that Sempra Generation owns and operates several power plants and Sempra LNG is developing LNG regasification terminals, additional environmental issues will 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. The company is required to obtain numerous governmental permits, licenses and other approvals to construct facilities and operate its businesses. Additionally, to comply with these legal requirements, it must spend significant sums on environmental monitoring, pollution control equipment and emissions fees. Increasing national and international concerns regarding global warming and mercury, nitrogen oxide and sulfur dioxide emissions could result in requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, that could adversely affect Sempra Generation. In addition, existing environmental regulations could be revised or reinterpreted and other new laws and regulations could be adopted or become applicable to the company and its facilities. Costs incurred 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 $22 million in 2004, $14 million in 2003 and $8 million in 2002 (includes only the company's share in cases of non-wholly owned affiliates). The cost of compliance with these regulations over the next five years is not expected to be significant.

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 near Mexicali, Baja California, Mexico. Additional information regarding the environmental studies is provided below under "Legal Proceedings."

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 assurance that these costs will be recovered in rates.

The environmental issues currently facing the company or resolved during the last three years include investigation and remediation of the California Utilities' manufactured-gas sites (29 completed as of December 31, 2004 and 15 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. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Not including the liability for SONGS marine mitigation, which SDG&E is participating in jointly with Edison, at December 31, 2004, the company's accrued liability for environmental matters was $53.6 million, of which $42.3 million is related to manufactured-gas sites, $8.7 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 $0.5 million to other hazardous waste sites. These accruals are expected to be paid ratably over the next three years.

Nuclear Insurance

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

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

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

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

Legal Proceedings

Except for the matters referred to below, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses. At December 31, 2004, the company had accrued approximately $250 million to provide for the costs of its legal proceedings, of which approximately $240 million related to cases arising from the 2000-2001 California energy crisis. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations.

DWR Contract

In 2003, Sempra Generation was awarded judgment in its favor in a state civil action between Sempra Generation and the DWR, in which the DWR sought to void its 10-year contract expiring in 2011 under which the company sells electricity to the DWR. The DWR filed an appeal of this ruling in January 2004. A decision by the appellate court is expected during 2005.

The DWR continues to accept scheduled power from Sempra Generation and, although it has disputed a portion of the billings and the manner of certain deliveries, it has paid all amounts billed, as required by the contract in the event of disputes. However, the DWR has commenced an arbitration proceeding disputing Sempra Generation's performance on various operational matters. Among other proposed remedies, the DWR has requested a declaration by the arbitration panel that Sempra Generation's performance violates the terms of the contract and constitutes a material breach of the agreement, permitting it to terminate the contract. Sempra Generation believes these claims are without merit. In November 2004, the arbitration panel denied Sempra Generation's motion to dismiss claims. Arbitration is expected to occur in mid-2005.

On June 25, 2003, the FERC issued orders upholding Sempra Generation'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 FERC 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 FERC pointed out that the contracts were entered into voluntarily in a market-based environment. The FERC 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. Oral argument on the appeal was held in December 2004, with a decision by the appellate court expected in 2005.

California Energy Crisis

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

Natural Gas Cases

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

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

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

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

In May 2003 and February 2004, two antitrust actions against various energy companies, including Sempra Energy and Sempra Commodities, were filed in San Diego Superior Court alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications and by entering into wash trades. Both actions were removed to U.S. District Court. In November 2003, an additional suit was filed in U.S. District Court. In September 2004, two additional lawsuits alleging substantially identical claims were filed against Sempra Energy and Sempra Commodities, among various other entities, in San Diego Superior and U.S. District Courts. Two additional, substantially identical lawsuits were filed against Sempra Commodities in November and December 2004 in the U.S. District Court in Fresno, California. In November 2004, the federal district court judge assigned to hear these cases determined that the cases originally filed in state court should return to that court system. On February 14, 2005, the California state court cases, including those described below, were assigned to the same judge overseeing the El Paso-related cases.

In July 2004, the City and County of San Francisco, the County of Santa Clara and the County of San Diego brought similar actions in San Diego Superior Court against various entities, including Sempra Energy, Sempra Commodities, SoCalGas and SDG&E. Six identical lawsuits were filed in the fourth quarter of 2004 in the Alameda and San Mateo Superior Courts and one in Sacramento Superior Court. In December 2004, the City of San Diego also filed an identical suit in San Diego Superior Court. These suits are also now pending before the same San Diego Superior Court judge described above.

In August 2003, a lawsuit was filed in the Southern District of New York against Sempra Energy and its subsidiary, Sempra Energy Solutions, alleging that the prices of natural gas options traded on the New York Mercantile Exchange (NYMEX) were unlawfully increased under the Federal Commodity Exchange Act by defendants' manipulation of transaction data provided to natural gas trade publications. In November 2003, another suit containing identical allegations was filed and consolidated with the New York action. Subsequently, plaintiffs dismissed Sempra Energy and Sempra Energy Solutions from these cases. On January 20, 2004, plaintiffs filed an amended consolidated complaint that named Sempra Commodities as a defendant in this lawsuit. In March 2004, defendants filed a motion to dismiss the action, which was denied by the court in September 2004. In October 2004, plaintiffs amended their complaint to allege that Sempra Commodities had engaged in natural gas wash trade transactions.

Electricity Cases

Various antitrust lawsuits, which seek class-action certification, allege that numerous entities, including Sempra Energy and certain subsidiaries (SDG&E, Sempra Commodities and Sempra Generation, depending on the lawsuit), that participated in the wholesale electricity markets unlawfully manipulated those markets. Collectively, these lawsuits allege damages against all defendants in an aggregate amount in excess of $16 billion (before trebling). In January 2003, the federal court granted a motion to dismiss one of these lawsuits, filed by the Snohomish County, Washington Public Utility District, on the grounds that the claims contained in the complaint were subject to the filed rate doctrine and were preempted by the Federal Power Act. That ruling was appealed to the Ninth Circuit U.S. Court of Appeals. In addition, in May 2003, the Port of Seattle filed a similar complaint against a number of energy companies, including Sempra Energy, Sempra Generation and Sempra Commodities. That action was dismissed by the San Diego U.S. District Court in May 2004. Plaintiff has appealed the decision. In May and June 2004, two lawsuits substantially identical to the Port of Seattle case were filed in Washington and Oregon U.S. District Courts. These cases were transferred to the San Diego U.S. District Court and motions to dismiss were granted in both cases on February 11, 2005. In October 2004, another case was filed in Santa Clara Superior Court against Sempra Generation, alleging substantively identical claims to those in the Port of Seattle case.

In September 2004, the Ninth Circuit U.S. Court of Appeals dismissed the suit against Sempra Energy, Sempra Commodities and Sempra Generation by the Snohomish County, Washington Public Utility District. The court ruled that the FERC, not civil courts, has exclusive jurisdiction over the matter. The company believes that this decision provides a precedent for the dismissal on the basis of federal preemption and the filed rate doctrine of the other lawsuits against the Sempra Energy companies claiming manipulation of the electricity markets. Snohomish County has appealed the Ninth Circuit decision to the U.S. Supreme Court.

CPUC Border Price Investigation

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California — Arizona border between March 2000 and May 2001. The California Utilities are the parties to the first phase of the investigation. If the investigation were to determine that the conduct of either of the California Utilities contributed to the natural gas price spikes that occurred during the investigation period, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. At December 31, 2004, the cumulative amount of shareholder awards, substantially all of which has been included in net income, was $65.3 million.

On November 16, 2004, the CPUC Administrative Law Judge assigned to the investigation issued a proposed decision for consideration by the full CPUC in the first phase of the investigation that was highly critical of SoCalGas' natural gas purchase, sales, hedging and storage activities and would find that SoCalGas exercised market power and manipulated the natural gas market, significantly contributing to natural gas price spikes that also increased electricity prices. The proposed decision did not include any adverse findings or make any adverse recommendations regarding SDG&E.

On December 16, 2004, the CPUC rejected the amended proposed decision by a 3-2 vote. The two commissioners who voted in favor of the proposed decision were Commissioners Lynch and Wood, whose terms on the CPUC expired at year end. It is now up to the remaining commissioners plus any new appointees to determine whether to issue an alternate proposed decision, hold additional hearings, or issue an order terminating the investigation.

The CPUC may hold additional rounds of hearings to consider whether other companies, including other California utilities as well as the company and its non-utility subsidiaries, contributed to the natural gas price spikes. No hearings have yet been scheduled.

FERC Refund Proceedings

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

In December 2002, a FERC ALJ issued preliminary findings indicating that the California PX and ISO owe power suppliers $1.2 billion for the October 2, 2000 through June 20, 2001 period (the $3.0 billion that the California PX and ISO still owe energy companies less $1.8 billion that the energy companies charged California customers in excess of the preliminarily determined competitive market clearing prices). On March 26, 2003, the FERC adopted its ALJ's findings, but changed the calculation of the refund by basing it on a different estimate of natural gas prices. The March 26 order estimates that the replacement formula for estimating natural gas prices will increase the refund obligations from $1.8 billion to more than $3 billion for the same time period. Pending in the Ninth Circuit are various parties' appeals on aspects of the FERC's order.

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

Sempra Commodities previously established reserves for its likely share of the original $1.8 billion discussed above. During 2004, Sempra Commodities recorded additional reserves to reflect the estimated effect of the FERC's revision of the benchmark prices to be used by the FERC to calculate refunds, and Sempra Generation recorded its share of the 2004 amounts related to its transactions with Sempra Commodities.

In a separate complaint filed with the FERC in 2002, the California Attorney General challenged the FERC's authority to establish a market-based rate regime, and further contended that, even if such a regime were valid, electricity sellers had failed to comply with the FERC's quarterly reporting requirements. The Attorney General requested that the FERC order refunds from suppliers to the California PX and ISO for the period prior to October 2, 2000, and for short-term bilateral transactions entered into with the California Energy Resources Scheduler. In May 2003, and upon rehearing in September 2003, the FERC dismissed the complaint, determining that its market-based rate system was lawful, and that refunds for non-compliance with its reporting requirements were unnecessary, and instead ordered sellers to restate their reports. After an appeal by the California Attorney General, in September 2004, the Ninth Circuit Court of Appeals upheld the FERC's authority to establish a market-based rate regime, but ordered remand of the case to the FERC for further proceedings, stating that failure to file transaction-specific quarterly reports gave the FERC authority to order refunds with respect to jurisdictional sellers. In October 2004, the FERC announced that it will not appeal the court's decision. Although a group of sellers has requested the Ninth Circuit to rehear this matter, the timing and substance of the FERC's response to the remand is not yet known. However, it is possible that the FERC could order refunds or disgorgement of profits for periods in addition to those covered by its prior refund orders and substantially increase the refunds that ultimately may be required to be paid by Sempra Commodities and other power suppliers.

FERC Manipulation Investigation

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

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. First, the FERC directed 43 entities, including Sempra Commodities 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 Sempra Commodities, to show cause why their activities, in partnership or in alliance with others, during the period between January 1, 2000 and 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 various entities to settle these issues. On October 31, 2003, Sempra Commodities agreed to pay $7.2 million in full resolution of these investigations. That liability was recorded as of December 31, 2003. The Sempra Commodities settlement was approved by the FERC on August 2, 2004. Certain California parties have sought rehearing of this order. SDG&E and the FERC resolved the matter through a settlement, which documents the ISO's finding that SDG&E did not engage in market activities in violation of the ISO or PX tariffs, and in which SDG&E agreed to pay $27,792 into a FERC-established fund.

On February 16, 2005, in connection with the California Senate Select Committee's investigation into Price Manipulation in the Wholesale Energy Market, Senator Dunn held a press conference and asserted that Sempra Commodities committed perjury in denying that it had engaged in three types of Enron-like strategies. Senator Dunn stated that he intends to refer the matter to the Sacramento District Attorney's Office and to seek contempt charges from the state Senate. The company denies these charges and will defend the matters vigorously.

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

Settlement of Claims Associated with the FERC's Investigations

During 2004, three settlements of claims associated with the FERC's investigations were announced. One settlement, in which SDG&E received a net payment of $11.6 million in August 2004, resolves all but a few claims against The Williams Companies and Williams Power Company for the period May 1, 2000 through June 20, 2001. Another settlement, in which SDG&E received a net payment of $13.5 million (of the $13.8 million total SDG&E settlement allocation) in November 2004, resolves all claims against Dynegy, NRG Energy and West Coast Power LLC for the period January 1, 2000 through June 20, 2001. A third settlement, in which SDG&E received a net payment of $14.4 million (of the $14.7 million total SDG&E settlement allocation) in January 2005, resolves specified claims against Duke Energy for the period January 1, 2000 though June 20, 2001. On January 13, 2005, SDG&E announced a $23.8 million settlement (including an unsecured claim in the Mirant bankruptcy proceeding valued at approximately $2.4 million), which resolves specified claims against merchant generator Mirant Corp. for the 2000-2001 energy crisis period. The settlement is pending final CPUC, FERC and U.S. Bankruptcy Court (for Mirant) approval. In all cases, the majority of the funds was received within 20 days of receiving FERC approval with the remainder contingent on certain actions by the FERC, the ISO and the PX. Receipt of the remaining amounts by SDG&E would take place at the conclusion of the FERC refund proceeding, now expected to be in early 2006. These funds would be received for the benefit of SDG&E's bundled customers and will reimburse SDG&E for the costs of litigating this matter. In November 2004, the CPUC approved SDG&E's proposal to apply 70 percent (about $17 million) of the refunds due to ratepayers to the AB 265 undercollection, thus facilitating the full recovery of the undercollections, as further discussed in Note 14. Claims alleged against Sempra Commodities are still pending.

Other Litigation

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

In May 2003, a federal judge issued an order finding that the DOE's environmental assessment of the TDM plant and another, unrelated Mexicali power 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 undertook to perform an Environmental Impact Study, which was completed in December 2004. Plaintiff may elect to dismiss its complaint or to further challenge the agency action. If a stipulation of dismissal is not filed to terminate the litigation by August 15, 2005, the DOE will file a motion by August 22, 2005, showing cause why the court should not set aside the permits. In that event, court hearings may take place in the fourth quarter of 2005.

The Peruvian appellate court has affirmed the dismissal of the charges against officers of Luz del Sur and others concerning the price of some utility networks transferred from the Peruvian government to Luz del Sur.

The Peruvian tax authorities (Sunat) continue to claim that Luz del Sur owes additional income taxes, interest and penalties related to a 1996 revaluation of assets. The tax court held a final hearing on November 10, 2004, with both parties presenting their cases. On November 17, 2004, Luz del Sur submitted a summary of its arguments to the tax court. The tax court ruled in December 2004 that a third revaluation study be done, which will be used as a basis for its decision. The Conata, the national assessors association, was selected to do the study. After the Conata completes its study (expected in mid 2005), the tax court has 90 business days to issue a verdict.

At December 31, 2004, Sempra Commodities 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 several factors, including the FERC refund case. The company believes adequate reserves have been recorded.

Argentine Investments

As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent further declines, Sempra Pipelines & Storage reduced the carrying value of its investment downward by a cumulative total of $198 million as of December 31, 2004 ($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).

A decision is expected in 2006 on Sempra Pipelines & Storage's arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of Sempra Pipelines & Storage's investments that has resulted from Argentine governmental actions. 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.

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. This delay by the DOE will lead to increased cost for spent fuel storage. This cost will be recovered through SONGS revenue unless the company is able to recover the increased cost from the federal government.

Electric Distribution System Conversion

Under a CPUC-mandated program, the cost of which is included in utility rates, and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2004, the aggregate unexpended amount of this commitment was $80 million. Capital expenditures for underground conversions were $23 million in 2004, $28 million in 2003 and $33 million in 2002.

Concentration Of Credit Risk

The company maintains credit policies and systems to manage overall credit risk. These policies include an evaluation of potential counterparties' financial condition and an assignment of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry. The 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, Sempra Generation has a contract with the DWR to supply up to 1,900 MW of power to the state over 10 years, beginning in 2001. Sempra Generation 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 are $50 million to $60 million.

Sempra Commodities 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, Sempra Commodities 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.

The developing LNG projects will result in significant reliance on the credit-worthiness of its major suppliers and customers of those projects.

NOTE 17. SEGMENT INFORMATION

The company has four separately managed reportable segments: SoCalGas, SDG&E, Sempra Commodities and Sempra Generation. 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. Sempra Commodities, based in Stamford, Connecticut, is primarily 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. As a result of the movement of the former Sempra Energy Solutions' commodities business into Sempra Commodities, Sempra Commodities' business also includes commodity sales on a retail basis to electricity and natural gas consumers. Sempra Generation primarily acquires, develops and operates power plants throughout the U.S. and Mexico and, as a result of the movement of the former Sempra Energy Solutions' energy businesses into Sempra Generation, provides energy services and facilities management. Sempra Generation also owns mineral rights in properties that produce petroleum and natural gas.

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 the FERC.

(Dollars in millions)	Years ended December 31, 2004		2003		2002	
OPERATING REVENUES						
Southern California Gas Company	**$3,997**	**42%**	$3,544	45%	$2,858	47%
San Diego Gas & Electric	**2,274**	**24**	2,311	29	1,725	29
Sempra Commodities	**1,680**	**18**	1,217	16	910	15
Sempra Generation	**1,647**	**18**	773	10	437	7
All other	**146**	**2**	99	1	155	3
Intersegment revenues	**(334)**	**(4)**	(57)	(1)	(37)	(1)
Total	**$9,410**	**100%**	$7,887	100%	$6,048	100%
INTEREST EXPENSE						
Southern California Gas Company	**$ 39**		$ 45		$ 44	
San Diego Gas & Electric	**68**		73		77	
Sempra Commodities	**23**		31		45	
Sempra Generation	**34**		33		10	
All other	**331**		256		190	
Intercompany elimination	**(173)**		(130)		(72)	
Total	**$ 322**		$ 308		$ 294	
INTEREST INCOME						
Southern California Gas Company	**$ 4**		$ 34		$ 5	
San Diego Gas & Electric	**25**		42		10	
Sempra Commodities	**8**		12		11	
Sempra Generation	**7**		17		4	
All other	**198**		129		84	
Intercompany elimination	**(173)**		(130)		(72)	
Total	**$ 69**		$ 104		$ 42	
DEPRECIATION AND AMORTIZATION						
Southern California Gas Company	**$ 255**	**41%**	$ 289	47%	$ 276	46%
San Diego Gas & Electric	**259**	**42**	242	39	230	39
Sempra Commodities	**23**	**4**	23	4	21	3
Sempra Generation	**44**	**7**	21	3	10	2
All other	**40**	**6**	40	7	59	10
Total	**$ 621**	**100%**	$ 615	100%	$ 596	100%
INCOME TAX EXPENSE (BENEFIT)						
Southern California Gas Company	**$ 154**	**80%**	$ 150	319%	$ 178	122%
San Diego Gas & Electric	**148**	**77**	148	315	91	62
Sempra Commodities	**161**	**83**	67	143	75	51
Sempra Generation	**91**	**47**	27	57	40	28
All other	**(361)**	**(187)**	(345)	(734)	(238)	(163)
Total	**$ 193**	**100%**	$ 47	100%	$ 146	100%
NET INCOME (LOSS)						
Southern California Gas Company	**$ 232**	**26%**	$ 209	32%	$ 212	36%
San Diego Gas & Electric	**208**	**23**	334	52	203	34
Sempra Commodities	**320**	**36**	128	20	165	28
Sempra Generation	**137**	**15**	80	12	42	7
All other	**(2)**	**—**	(102)	(16)	(31)	(5)
Total	**$ 895**	**100%**	$ 649	100%	$ 591	100%

(Dollars in millions)	2004		2003		2002	
	At December 31 or years ended December 31,					
ASSETS						
Southern California Gas Company	**$ 5,502**	**23%**	$ 5,349	24%	$ 5,403	27%
San Diego Gas & Electric	**6,834**	**29**	6,461	29	6,285	31
Sempra Commodities	**7,574**	**32**	6,144	28	5,780	28
Sempra Generation	**2,738**	**12**	2,550	12	1,633	8
All other	**1,997**	**8**	1,988	9	1,783	9
Intersegment receivables	**(1,002)**	**(4)**	(504)	(2)	(642)	(3)
Total	**$23,643**	**100%**	$21,988	100%	$20,242	100%
CAPITAL EXPENDITURES						
Southern California Gas Company	**$ 311**	**29%**	$ 318	30%	$ 331	27%
San Diego Gas & Electric	**414**	**38**	444	42	400	33
Sempra Commodities	**126**	**12**	51	5	21	2
Sempra Generation	**141**	**13**	144	14	359	30
All other	**91**	**8**	92	9	103	8
Total	**$ 1,083**	**100%**	$ 1,049	100%	$ 1,214	100%
GEOGRAPHIC INFORMATION						
Long-lived assets						
United States	**$10,975**	**89%**	$10,380	89%	$ 9,548	90%
Latin America	**1,177**	**10**	1,121	10	1,062	10
Europe	**98**	**1**	87	1	18	—
Canada	**—**	**—**	—	—	3	—
Total	**$12,250**	**100%**	$11,588	100%	$10,631	100%
Operating revenues						
United States	**$ 8,518**	**91%**	$ 7,211	92%	$ 5,503	91%
Latin America	**311**	**3**	315	4	168	3
Europe	**519**	**6**	323	4	328	6
Canada	**37**	**—**	10	—	28	—
Asia	**25**	**—**	28	—	21	—
Total	**$ 9,410**	**100%**	$ 7,887	100%	$ 6,048	100%

NOTE 18. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarters ended			
(Dollars and shares in millions, except per share amounts)	March 31	June 30	September 30	December 31
2004				
Operating revenues	**$2,360**	**$1,996**	**$2,165**	**$2,889**
Operating expenses	**2,028**	**1,776**	**1,820**	**2,514**
Operating income	**$ 332**	**$ 220**	**$ 345**	**$ 375**
Income from continuing operations	**$ 221**	**$ 129**	**$ 231**	**$ 339**
Net income	**$ 197**	**$ 121**	**$ 231**	**$ 346**
Basic earnings per share:				
Income from continuing operations	**$ 0.97**	**$ 0.56**	**$ 1.01**	**$ 1.47**
Net income	**$ 0.86**	**$ 0.52**	**$ 1.01**	**$ 1.50**
Average common shares outstanding	**228.1**	**230.4**	**229.4**	**230.8**
Diluted earnings per share:				
Income from continuing operations	**$ 0.96**	**$ 0.55**	**$ 0.98**	**$ 1.43**
Net income	**$ 0.85**	**$ 0.52**	**$ 0.98**	**$ 1.46**
Average common shares outstanding	**231.1**	**234.3**	**235.9**	**237.5**
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
Basic earnings per share:				
Income before cumulative effect of changes in accounting principles	$ 0.57	$ 0.56	$ 1.01	$ 1.12
Net income	$ 0.43	$ 0.56	$ 1.01	$ 1.05
Average common shares outstanding	206.4	207.6	208.8	224.0
Diluted earnings per shares:				
Income before cumulative effect of changes in accounting principles	$ 0.56	$ 0.55	$ 1.00	$ 1.11
Net income	$ 0.42	$ 0.55	$ 1.00	$ 1.03
Average common shares outstanding	207.8	210.2	212.3	227.2

Operating revenues and expenses in the fourth quarter of 2004 included the favorable impact of the final cost of service decision and operating expenses included litigation costs recorded in the fourth quarter. Net income in the first and second quarters of 2004 included $24 million and $8 million, respectively, of losses related to the discontinuance and disposal of AEG. Net income in the fourth quarter of 2004 included the $38 million favorable impact of income tax issues related to the reduced estimate of federal and state income tax liabilities for certain prior years and the $7 million favorable tax adjustment related to AEG. Note 4 provides a discussion of discontinued operations.

Operating revenues in the third quarter of 2003 included the recognition of $116 million before-tax related to the approved settlement of intermediate-term purchase power contracts at SDG&E and $48 million of natural gas procurement awards at SoCalGas. The after-tax impacts to net income were $65 million and $29 million, respectively. Additionally, operating expenses in the third quarter of 2003 were impacted by a $77 million impairment charge to write down the carrying value of the assets of Frontier

Energy and a $74 million before-tax charge for litigation and for losses associated with a sublease of portions of the SoCalGas headquarters building. The after-tax impacts to net income were $47 million and $43 million, respectively.

In the first quarter of 2003, net income reflected a $29 million charge related to the cumulative effect of a change in accounting principle at Sempra Commodities. Net income in the fourth quarter of 2003 included $118 million related to the favorable resolution of income tax issues at the California Utilities and the unfavorable net impact of $17 million related to the cumulative effect of changes in accounting principles.

QUARTERLY COMMON STOCK DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2004				
Market price				
High	**$32.99**	**$34.90**	**$37.19**	**$37.93**
Low	**$29.51**	**$30.80**	**$33.97**	**$31.00**
2003				
Market price				
High	$26.00	$29.40	$30.33	$30.90
Low	$22.25	$24.05	$27.31	$26.36

Dividends declared were $0.25 per share in each quarter.