UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2004

Commission file number 1-14201

Sempra Energy
(Exact name of registrant as specified in its charter)

California	33-0732627
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

101 Ash Street, San Diego, California 92101
(Address of principal executive offices)
(Zip Code)

(619) 696-2034
(Registrant's telephone number, including area code)

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

Yes X No

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes X No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock outstanding on October 31, 2004: 233,389,125

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report contains statements that are not historical fact and constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The words "estimates," "believes," "expects," "anticipates," "plans," "intends," "may," "could," "would" and "should" or similar expressions, or discussions of strategy or of plans are intended to identify forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future results may differ materially from those expressed in these forward-looking statements.

Forward-looking statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others, local, regional, national and international economic, competitive, political, legislative and regulatory conditions and developments; actions by the California Public Utilities Commission, the California Legislature, the California Department of Water Resources, and the Federal Energy Regulatory Commission and other regulatory bodies in the United States and other countries; capital market conditions, inflation rates, interest rates and exchange rates; energy and trading markets, including the timing and extent of changes in commodity prices; the availability of natural gas; weather conditions and conservation efforts; war and terrorist attacks; business, regulatory, environmental and legal decisions and requirements; the status of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company's business described in this report and other reports filed by the company from time to time with the Securities and Exchange Commission.

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS.
<table>
SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME
(Dollars in millions, except per share amounts)
<caption>

<s>	Three months ended September 30, 2004 <c>	Three months ended September 30, 2003 <c>
OPERATING REVENUES		
California utilities:		
Natural gas	$ 909	$ 870
Electric	445	576
Other	811	612
Total operating revenues	2,165	2,058
OPERATING EXPENSES		
California utilities:		
Cost of natural gas	438	372
Cost of electric fuel and purchased power	143	128
Other cost of sales	484	371
Other operating expenses	530	668
Depreciation and amortization	171	158
Franchise fees and other taxes	54	54
Total operating expenses	1,820	1,751
Operating income	345	307
Other income - net	40	34
Interest income	25	8
Interest expense	(74)	(78)
Preferred dividends of subsidiaries	(2)	(2)
Income before income taxes	334	269
Income tax expense	103	58
Net income	$ 231	$ 211
Basic earnings per share:		
Net income	$ 1.01	$ 1.01
Weighted-average number of shares outstanding (thousands)	229,376	208,816
Diluted earnings per share:		
Net income	$ 0.98	$ 1.00
Weighted-average number of shares outstanding (thousands)	235,936	212,273
Dividends declared per share of common stock	$ 0.25	$ 0.25

See notes to Consolidated Financial Statements.
</table>

<table>
SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME
(Dollars in millions, except per share amounts)
<caption>

<s>	Nine months ended September 30, 2004 <c>	2003 <c>
OPERATING REVENUES		
California utilities:		
Natural gas	$ 3,189	$ 2,961
Electric	1,246	1,368
Other	2,086	1,492
Total operating revenues	6,521	5,821
OPERATING EXPENSES		
California utilities:		
Cost of natural gas	1,744	1,529
Cost of electric fuel and purchased power	425	428
Other cost of sales	1,186	886
Other operating expenses	1,597	1,631
Depreciation and amortization	501	455
Franchise fees and other taxes	171	167
Total operating expenses	5,624	5,096
Operating income	897	725
Other income - net	58	38
Interest income	58	30
Interest expense	(234)	(223)
Preferred dividends of subsidiaries	(7)	(8)
Trust preferred distributions by subsidiary	--	(9)
Income from continuing operations before income taxes	772	553
Income tax expense	191	109
Income from continuing operations	581	444
Loss from discontinued operations, net of tax (Note 4)	(30)	--
Loss on disposal of discontinued operations, net of tax (Note 4)	(2)	--
Income before cumulative effect of change in accounting principle	549	444
Cumulative effect of change in accounting principle, net of tax (Note 2)	--	(29)
Net income	$ 549	$ 415
Basic earnings per share:		
Income from continuing operations	$ 2.55	$ 2.14
Discontinued operations, net of tax	(0.14)	--
Cumulative effect of change in accounting principle, net of tax	--	(0.14)
Net income	$ 2.41	$ 2.00
Weighted-average number of shares outstanding (thousands)	227,412	207,620
Diluted earnings per share:		
Income from continuing operations	$ 2.50	$ 2.12
Discontinued operations, net of tax	(0.14)	--
Cumulative effect of change in accounting principle, net of tax	--	(0.14)
Net income	$ 2.36	$ 1.98
Weighted-average number of shares outstanding (thousands)	232,366	210,160
Dividends declared per share of common stock	$ 0.75	$ 0.75

See notes to Consolidated Financial Statements.
</table>

<table>
SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
<caption>

<s>	September 30, 2004 <c>	December 31, 2003 <c>
ASSETS		
Current assets:		
Cash and cash equivalents	$ 267	$ 432
Short-term investments	--	363
Accounts receivable - trade	685	875
Accounts and notes receivable – other	85	127
Due from affiliate	7	--
Income taxes receivable	--	1
Deferred income taxes	58	2
Interest receivable	82	62
Trading assets	6,156	5,250
Regulatory assets arising from fixed-price contracts and other derivatives	155	144
Other regulatory assets	109	89
Inventories	225	147
Other	198	157
Current assets of continuing operations	8,027	7,649
Current assets of discontinued operations	82	220
Total current assets	8,109	7,869
Investments and other assets:		
Due from affiliates	45	55
Regulatory assets arising from fixed-price contracts and other derivatives	530	650
Other regulatory assets	476	552
Nuclear decommissioning trusts	575	570
Investments	1,132	1,114
Sundry	750	706
Total investments and other assets	3,508	3,647
Property, plant and equipment:		
Property, plant and equipment	15,927	15,317
Less accumulated depreciation and amortization	(5,080)	(4,843)
Property, plant and equipment - net	10,847	10,474
Total assets	$ 22,464	$ 21,990

See notes to Consolidated Financial Statements.
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<table>
SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
<caption>

<s>	September 30, 2004 <c>	December 31, 2003 <c>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	$ 435	$ 28
Accounts payable - trade	745	779
Accounts payable – other	89	62
Income taxes payable	302	156
Deferred income taxes	--	26
Trading liabilities	4,860	4,457
Dividends and interest payable	134	136
Regulatory balancing accounts - net	347	424
Fixed-price contracts and other derivatives	164	148
Current portion of long-term debt	99	1,433
Other	690	681
Current liabilities of continuing operations	7,865	8,330
Current liabilities of discontinued operations	19	52
Total current liabilities	7,884	8,382
Long-term debt	4,414	3,841
Deferred credits and other liabilities:		
Due to affiliates	362	362
Customer advances for construction	85	89
Postretirement benefits other than pensions	121	131
Deferred income taxes	170	208
Deferred investment tax credits	80	84
Regulatory liabilities arising from cost of removal obligations	2,331	2,238
Regulatory liabilities arising from asset retirement obligations	300	303
Other regulatory liabilities	112	108
Fixed-price contracts and other derivatives	530	680
Asset retirement obligations	321	313
Deferred credits and other	1,194	1,182
Total deferred credits and other liabilities	5,606	5,698
Preferred stock of subsidiaries	179	179
Contingencies and commitments (Note 7)		
SHAREHOLDERS' EQUITY		
Preferred stock (50 million shares authorized; none issued)	--	--
Common stock (750 million shares authorized; 233 million and 227 million shares outstanding at September 30, 2004 and December 31, 2003, respectively)	2,166	2,028
Retained earnings	2,674	2,298
Deferred compensation relating to ESOP	(33)	(35)
Accumulated other comprehensive income (loss)	(426)	(401)
Total shareholders' equity	4,381	3,890
Total liabilities and shareholders' equity	$ 22,464	$ 21,990

See notes to Consolidated Financial Statements.
</table>

<table>
SEMPRA ENERGY
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)
<caption>

	Nine months ended September 30,	
	2004	2003
<s>	<c>	<c>
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 549	$ 415
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss from discontinued operations, net of tax	30	--
Loss on disposal of discontinued operations, net of tax	2	--
Cumulative effect of change in accounting principle	--	29
Depreciation and amortization	501	455
Impairment losses	8	79
Deferred income taxes and investment tax credits	(7)	(160)
Other – net	8	38
Net changes in other working capital components	(523)	75
Changes in other assets	(66)	(36)
Changes in other liabilities	21	28
Net cash provided by continuing operations	523	923
Net cash used in discontinued operations	(30)	--
Net cash provided by operating activities	493	923
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(782)	(664)
Proceeds from sale of assets	371	--
Proceeds from disposal of discontinued operations	137	--
Investments and acquisitions of subsidiaries, net of cash acquired	(70)	(182)
Dividends received from affiliates	50	21
Affiliate loan	--	(54)
Other - net	--	(8)
Net cash used in investing activities	(294)	(887)
CASH FLOWS FROM FINANCING ACTIVITIES		
Common dividends paid	(162)	(155)
Issuances of common stock	120	81
Repurchases of common stock	(1)	(6)
Issuances of long-term debt	897	400
Payments on long-term debt	(1,648)	(481)
Increase in short-term debt - net	434	89
Other - net	(4)	(8)
Net cash used in financing activities	(364)	(80)
Decrease in cash and cash equivalents	(165)	(44)
Cash and cash equivalents, January 1	432	455
Cash and cash equivalents, September 30	$ 267	$ 411
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Interest payments, net of amounts capitalized	$ 229	$ 216
Income tax payments, net of refunds	$ 120	$ 97

See notes to Consolidated Financial Statements.
</table>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. GENERAL

This Quarterly Report on Form 10-Q is that of Sempra Energy (the company), a California-based Fortune 500 holding company. Sempra Energy's subsidiaries include San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas) (collectively referred to herein as the California Utilities); Sempra Energy Global Enterprises (Global), which is the holding company for Sempra Energy Trading (SET), Sempra Energy Resources (SER), Sempra Energy International (SEI), Sempra Energy LNG (SELNG) and other, smaller businesses; Sempra Energy Financial (SEF); and additional smaller businesses. The financial statements herein are the Consolidated Financial Statements of Sempra Energy and its consolidated subsidiaries.

The accompanying Consolidated Financial Statements have been prepared in accordance with the interim-period-reporting requirements of Form 10-Q. Results of operations for interim periods are not necessarily indicative of results for the entire year. In the opinion of management, the accompanying statements reflect all adjustments necessary for a fair presentation. These adjustments are only of a normal recurring nature. Certain changes in classification have been made to prior presentations to conform to the current financial statement presentation. Specifically, certain December 31, 2003 income tax liabilities have been reclassified from Deferred Income Taxes to current Income Taxes Payable and to Deferred Credits and Other Liabilities to conform to the current presentation of these items.

Information in this Quarterly Report is unaudited and should be read in conjunction with the Annual Report on Form 10-K for the year ended December 31, 2003 (Annual Report) and the Quarterly Reports on Form 10-Q for the first and second quarters of 2004.

The company's significant accounting policies are described in Note 1 of the notes to Consolidated Financial Statements in the Annual Report. The same accounting policies are followed for interim reporting purposes.

The company follows the guidance of Statement of Financial Accounting Standards (SFAS) 142*, Goodwill and Other Intangible Assets.* The carrying amount of goodwill (included in Noncurrent Sundry Assets on the Consolidated Balance Sheets) was $188 million as of December 31, 2003 and September 30, 2004.

The California Utilities account for the economic effects of regulation on utility operations in accordance with SFAS No. 71*, Accounting for the Effects of Certain Types of Regulation.*

The following tables provide the per share computations for income from continuing operations.

<table>
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	Three months ended September 30, 2004			Three months ended September 30, 2003		
	Income (millions) (numerator)	Shares (thousands) (denominator)	Per Share Amounts	Income (millions) (numerator)	Shares (thousands) (denominator)	Per Share Amounts
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Basic EPS:						
Income from continuing operations	$ 231	229,376	$ 1.01	$ 211	208,816	$ 1.01
Effect of dilutive securities:						
Stock options and restricted stock awards		3,663	(0.02)		3,457	(0.01)
Equity Units		2,897	(0.01)		--	--
Diluted EPS:						
Income from continuing operations	$ 231	235,936	$ 0.98	$ 211	212,273	$ 1.00

	Nine months ended September 30, 2004			Nine months ended September 30, 2003		
	Income (millions) (numerator)	Shares (thousands) (denominator)	Per Share Amounts	Income (millions) (numerator)	Shares (thousands) (denominator)	Per Share Amounts
Basic EPS:						
Income from continuing operations	$ 581	227,412	$ 2.55	$ 444	207,620	$ 2.14
Effect of dilutive securities:						
Stock options and restricted stock awards		3,344	(0.03)		2,540	(0.02)
Equity Units		1,610	(0.02)		--	--
Diluted EPS:						
Income from continuing operations	$ 581	232,366	$ 2.50	$ 444	210,160	$ 2.12

</table>

Additional information regarding the Equity Units is provided in Note 12 of the Annual Report.

NOTE 2. NEW ACCOUNTING STANDARDS

Stock-Based Compensation: On March 31, 2004, the Financial Accounting Standards Board (FASB) issued a proposed Exposure Draft to amend SFAS 123*, Accounting for Stock-Based Compensation.* The proposed statement would eliminate the choice of accounting for share-based compensation transactions using Accounting Principles Board (APB) Opinion No. 25*, Accounting for Stock Issued to Employees*, whereby no expense is recorded for most stock options, and instead would require that such transactions be accounted for using a fair-value-based method, whereby expense is recorded for stock options. It would also prohibit application by restating prior periods and would require that expense ultimately be recognized only for those options that actually vest. A final statement is expected to be issued in the fourth quarter of 2004 and be effective July 1, 2005.

The following table provides the pro forma effects that would have resulted if stock options had been expensed.

<table>
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(Dollars in millions, except for per share amounts)	Three months ended September 30, 2004	Three months ended September 30, 2003	Nine months ended September 30, 2004	Nine months ended September 30, 2003
<S>	<C>	<C>	<C>	<C>
Net income as reported	$ 231	$ 211	$ 549	$ 415
Stock-based employee compensation expense as recorded, net of tax	6	3	15	17
Total stock-based employee compensation under fair-value method for all awards, net of tax	(9)	(5)	(21)	(23)
Pro forma net income	$ 228	$ 209	$ 543	$ 409
Earnings per share:				
Basic--as reported	$ 1.01	$ 1.01	$ 2.41	$ 2.00
Basic--pro forma	$ 0.99	$ 1.00	$ 2.39	$ 1.97
Diluted--as reported	$ 0.98	$ 1.00	$ 2.36	$ 1.98
Diluted--pro forma	$ 0.97	$ 0.98	$ 2.34	$ 1.95

</table>

SFAS 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits": This statement revises required disclosures about employers' pension plans and other postretirement benefit plans, effective in 2004. It requires disclosures beyond those in the original SFAS 132 related to the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement benefit plans. In addition, it requires interim-period disclosures regarding the amount of net periodic benefit cost recognized and the total amount of the employers' contributions paid and expected to be paid during the current fiscal year. It does not change the measurement or recognition of those plans.

The following table provides the components of benefit costs for the three and nine months ended September 30:

<table>
<caption>

	Pension Benefits		Other Postretirement Benefits	
	Three months ended September 30,		Three months ended September 30,	
(Dollars in millions)	2004	2003	2004	2003
<S>	<C>	<C>	<C>	<C>
Service cost	$ 12	$ 7	$ 5	$ 5
Interest cost	38	38	10	13
Expected return on assets	(38)	(40)	(9)	(9)
Amortization of:				
Transition obligation	--	--	2	3
Prior service cost	3	2	(1)	(1)
Actuarial loss	3	6	1	5
Regulatory adjustment	(9)	(1)	7	(3)
Total net periodic benefit cost	$ 9	$ 12	$ 15	$ 13

	Pension Benefits		Other Postretirement Benefits	
	Nine months ended September 30,		Nine months ended September 30,	
(Dollars in millions)	2004	2003	2004	2003
Service cost	$ 36	$ 39	$ 16	$ 14
Interest cost	115	113	39	41
Expected return on assets	(115)	(121)	(27)	(26)
Amortization of:				
Transition obligation	--	--	7	7
Prior service cost	7	7	(1)	(1)
Actuarial loss	9	9	7	8
Regulatory adjustment	(25)	(11)	7	(3)
Total net periodic benefit cost	$ 27	$ 36	$ 48	$ 40

</table>

Note 8 of the notes to Consolidated Financial Statements in the Annual Report discusses the company's expected contribution to its pension plans and other postretirement benefit plans in 2004. For the nine months ended September 30, 2004, $10 million and $44 million of contributions have been made to its pension plans and other postretirement benefit plans, respectively, including $1 million and $14 million, respectively, for the quarter ended September 30, 2004.

FASB Staff Position (FSP) 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003": In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was enacted. 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.

In May 2004, the FASB issued FSP 106-2 which requires that the effects of the federal subsidy be considered an actuarial gain and be recognized in the same manner as other actuarial gains and losses. In addition, FSP 106-2 requires certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. During the third quarter of 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 net periodic benefit cost for 2004 by $13 million.

The net periodic postretirement benefit costs for the three and nine months ended September 30, 2004 were reduced by $10 million, before regulatory adjustments, to reflect the expected subsidy as a result of the Act.

The following tables provide the impact of the Act on components of net periodic postretirement benefit costs. The three-month period includes the entire nine-month subsidy since none of the subsidy was recorded until the third quarter.

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<caption>

	Three months ended September 30, 2004		
(Dollars in millions)	Before Federal Subsidy	Effect of Subsidy	After Federal Subsidy
<s>	<c>	<c>	<c>
Service cost	$ 6	$ (1)	$ 5
Interest cost	15	(5)	10
Expected return on assets	(9)	--	(9)
Amortization of:			
Transition obligation	2	--	2
Prior service cost	(1)	--	(1)
Actuarial (gain) loss	5	(4)	1
Regulatory adjustment	(2)	9	7
Total net periodic benefit cost	$ 16	$ (1)	$ 15

(Dollars in millions)	Nine months ended September 30, 2004 Before Federal Subsidy	Effect of Subsidy	After Federal Subsidy
Service cost	$ 17	$ (1)	$ 16
Interest cost	44	(5)	39
Expected return on assets	(27)	--	(27)
Amortization of:			
Transition obligation	7	--	7
Prior service cost	(1)	--	(1)
Actuarial (gain) loss	11	(4)	7
Regulatory adjustment	(2)	9	7
Total net periodic benefit cost	$ 49	$ (1)	$ 48

</table>

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 also requires the reclassification of utilities' estimated removal costs, which have historically been recorded in accumulated depreciation, to a regulatory liability. At September 30, 2004 and December 31, 2003, the estimated removal costs recorded as a regulatory liability were $1.4 billion at both dates for SoCalGas, and $882 million and $846 million, respectively, for SDG&E.

The change in the asset retirement obligations for the nine months ended September 30, 2004 is as follows (dollars in millions):

Balance as of January 1, 2004	$ 337
Accretion expense (interest)	17
Payments	(9)
Balance as of September 30, 2004	$ 345*

* 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. The proposed interpretation would be effective for the company on December 31, 2005.

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 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, whereby derivatives are not required to be marked to market when the contract is usually settled by the physical delivery of natural gas. ("Netting" refers to contract settlement by paying or receiving the monetary difference between the contract price and the market price at the date on which physical delivery would have occurred.) The company has determined that all natural gas contracts are subject to unplanned netting and as such, these contracts are marked to market. In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 are marked to market. Implementation of SFAS 149 did not have a material impact on reported net income. Additional information on derivative instruments is provided in Note 5.

***SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity"*:** 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. On December 31, 2003, the $200 million of mandatorily redeemable trust preferred securities was further reclassified to Due to Affiliates upon the adoption of FASB Interpretation No. (FIN) 46 as discussed below.

Emerging Issues Task Force (EITF) 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": In accordance with the EITF's rescission of Issue 98-10 by the release of Issue 02-3, the company no longer marks to market energy-related contracts unless the contracts meet the requirements stated under SFAS 133 and SFAS 149. A substantial majority of the company's contracts do meet these requirements. 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. However, net income for the third quarter of 2004 was $38 million lower than the true economic value of SET's activities due to the EITF's rescission of Issue 98-10. Additional information on derivative instruments is provided in Note 5.

FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees": As of September 30, 2004, substantially all of the company's guarantees were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries. Significant guarantees for which disclosure is required are the mandatorily redeemable trust preferred securities and $25 million related to debt issued by Chilquinta Energia Finance, LLC, an unconsolidated affiliate. The mandatorily redeemable trust preferred securities were also affected by FIN 46, as described below. In addition, the company provided American Electric Power (AEP) a guarantee of up to $75 million for specified liabilities described in the agreement for the company's acquisition of certain AEP power plants. The company does not expect material losses to result from this guarantee because performance is not expected to be required and, therefore, has determined that the fair value of the guarantee is immaterial. SDG&E and SoCalGas have a residual value guarantee under a fleet lease arrangement. As of September 30, 2004, the company had no liabilities recorded for the fleet lease guarantees due to the immaterial amount of the estimated fair value of such guarantees.

FIN 46, "Consolidation of Variable Interest Entities (an interpretation of Accounting Research Bulletin (ARB) No. 51)": FIN 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the entity. Variable interest entities (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 Atlantic Electric & Gas (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 disposal of AEG, which occurred in April 2004.

In accordance with this interpretation, the company deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. The trust has no assets except for its receivable from the company. Due to the deconsolidation of this entity, Sempra Energy reclassified $200 million of mandatorily redeemable trust preferred securities to Due to Affiliates on its Consolidated Balance Sheets.

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.

NOTE 3. COMPREHENSIVE INCOME

The following is a reconciliation of net income to comprehensive income.

	Three months ended September 30,		Nine months ended September 30,	
(Dollars in millions)	2004	2003	2004	2003
Net income	$ 231	$ 211	$ 549	$ 415
Minimum pension liability adjustments	--	--	--	(6)
Foreign currency adjustments	13	(13)	3	31
Financial instruments	(15)	--	(28)	--
Comprehensive income	$ 229	$ 198	$ 524	$ 440

NOTE 4. DISCONTINUED OPERATIONS

During the first quarter of 2004, Sempra Energy's Board of Directors approved management's plan to dispose of its interest in AEG, which resulted in a loss of $2 million after taxes in the second quarter, which has been reported separately on the Statements of Consolidated Income.

The net losses from discontinued operations were $32 million for the nine months ended September 30, 2004 (including the $2 million loss on disposal). There was no operating activity for the quarter ended September 30, 2004. During 2003, the company accounted for its investment in AEG under the equity method of accounting. As such, for the nine-month and three-month periods ended September 30, 2003, the company recorded its share of AEG's net income, $1 million and $7 million, respectively, in Other Income – Net on the Statements of Consolidated Income. Additionally, for those nine-month and three-month periods the company recorded $2 million and $1 million, respectively, of interest income, and for both periods the company recorded offsetting income tax expense of $1 million. Effective December 31, 2003, AEG has been consolidated as a result of the adoption of FIN 46. This is discussed further in the Annual Report.

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

(Dollars in millions)	Nine months ended September 30, 2004
Operating revenues	$ 201
Loss from discontinued operations, before income taxes	$ (30)
Loss on disposal of discontinued operations, before income taxes	$ (6)

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

(Dollars in millions)	September 30, 2004	December 31, 2003
Assets:		
Accounts receivable	$ 37	$ 137
Other current assets	45	83
Total assets	$ 82	$ 220
Liabilities:		
Accounts payable	$ --	$ 36
Other current liabilities	19	16
Total liabilities	$ 19	$ 52

NOTE 5. FINANCIAL INSTRUMENTS

As described in Note 10 of the notes to Consolidated Financial Statements in the Annual Report, the company follows the guidance of SFAS 133 as amended by SFAS 138 and 149 (collectively SFAS 133) to account for its derivative instruments and hedging activities. Derivative instruments and related hedged items are recognized as either assets or liabilities on the balance sheet, measured at fair value. Except at the California Utilities, where such changes are balanced in the ratemaking process, changes in the fair value of derivatives are recognized in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in Other Comprehensive Income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. Any ineffective portion is reported in earnings immediately.

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in energy and other commodity prices, which are subject to significant and often volatile fluctuation. The company also uses derivative financial instruments to reduce its exposure to fluctuations in foreign currency exchange rates. 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 or paid by the company and, in the case of the California Utilities, their customers. The company also periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. The use of derivative financial instruments by the California Utilities is subject to certain limitations imposed by company policy and regulatory requirements.

Contracts that meet the definition of normal purchases and sales generally are long-term contracts that are settled by physical delivery and, therefore, are eligible for the normal purchases and sales exception of SFAS 133. The contracts are accounted for under accrual accounting and recorded in Revenues or Cost of Sales on the Statements of Consolidated Income when physical delivery occurs. Due to the adoption of SFAS 149, the company has determined that its natural gas contracts entered into after September 30, 2003 generally do not qualify for the normal purchases and sales exception and, accordingly, are marked to market.

Fixed-price Contracts and Other Derivatives

Fixed-price Contracts and Other Derivatives on the Consolidated Balance Sheets primarily reflect the California Utilities' unrealized gains and losses related to long-term delivery contracts for purchased power and natural gas transportation. The California Utilities have established offsetting regulatory assets and liabilities to the extent that these gains and losses are included in the calculation of 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. If 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 changes in Fixed-price Contracts and Other Derivatives on the Consolidated Balance Sheets for the nine months ended September 30, 2004 were primarily due to the settlement of the contingent purchase price obligation arising from the company's acquisition of the proposed Cameron liquefied natural gas (LNG) project described below and the physical deliveries under long-term purchased-power and natural gas transportation contracts. For the nine months ended September 30, 2004, pre-tax income from transactions associated with fixed-price contracts and other derivatives included $13 million for the settlement of the Cameron contingency, which occurred during the first quarter. The transactions associated with fixed-price contracts and other derivatives had no material impact to the Statements of Consolidated Income for the nine months ended September 30, 2003.

Trading Assets and Trading Liabilities

Trading Assets and Trading Liabilities primarily arise from the activities of SET. SET derives revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum, petroleum products, metals and other commodities, for which it quotes bid and ask prices to other market makers and end users. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. SET utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and often volatile fluctuation. These instruments include futures, forwards, swaps and options, and represent contracts with counterparties under which payments are linked to or derived from energy market indices or on terms predetermined by the contract, which may or may not be financially settled by SET. Sempra Energy guarantees many of SET's transactions.

Derivative trading instruments are recorded by SET 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. Trading Assets or Trading Liabilities 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 over-the-counter (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 offset exists under an enforceable netting arrangement. Other derivatives which qualify as hedges are accordingly recorded under hedge accounting.

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 market 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 and carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates, as applicable. Energy commodity inventory is recorded at the lower of cost or market; however metals inventories continue to be recorded at fair value in accordance with ARB 43, *Restatement and Revision of Accounting Research Bulletins*.

The carrying values of SET's trading assets and trading liabilities are as follows:

(Dollars in millions)	September 30, 2004	December 31, 2003
Trading Assets		
Unrealized gains on swaps and forwards	$ 2,063	$ 1,043
OTC commodity options purchased	819	459
Due from trading counterparties	1,699	2,183
Due from commodity clearing organizations and clearing brokers	270	134
Commodities owned	1,243	1,420
Other	6	1
Total	$ 6,100	$ 5,240
Trading Liabilities		
Unrealized losses on swaps and forwards	$ 1,883	$ 1,095
OTC commodity options written	397	226
Due to trading counterparties	2,175	2,195
Repurchase obligations	371	866
Commodities not yet purchased	--	56
Total	$ 4,826	$ 4,438

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

SET's credit risk from physical and financial instruments as of September 30, 2004 is represented by their positive fair value after consideration of collateral. Options written do not expose SET to credit risk. Exchange traded futures and options are not deemed to have significant credit exposure since the exchanges guarantee that every contract will be properly settled on a daily basis.

The following table summarizes the counterparty credit quality (as determined by rating agencies or internal models intended to approximate rating-agency determinations) and exposure for SET at September 30, 2004 and December 31, 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 September 30, 2004 and December 31, 2003, respectively.

(Dollars in millions)	September 30, 2004	December 31, 2003
Counterparty credit quality		
Commodity exchanges	$ 270	$ 134
AAA	5	5
AA	489	310
A	593	463
BBB	820	345
Below investment grade	562	357
Total	$ 2,739	$ 1,614

NOTE 6. REGULATORY MATTERS

ELECTRIC INDUSTRY REGULATION

The restructuring of California's electric utility industry has significantly affected the company's electric utility operations. In addition, the energy crisis of 2000-2001 caused the California Public Utilities Commission (CPUC) to adjust its plan for restructuring the electricity industry. The background of these issues is described in the Annual Report.

At September 30, 2004, the AB 265 Undercollection had been reduced to $23 million and SDG&E expects that the undercollection will be eliminated by the end of 2004.

The California Department of Water Resources' (DWR) operating agreement with SDG&E, approved by the CPUC, provides that SDG&E is acting as a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions under the DWR contracts allocated to SDG&E's customers. Legal and financial responsibility associated with these activities continues to reside with the DWR. Therefore, 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. An interim allocation based on the current 2003 methodology was utilized beginning January 1, 2004, and will remain in effect until a decision is reached on a permanent methodology. In April 2004, Southern California Edison (Edison), Pacific Gas & Electric (PG&E) and a northern California consumer advocacy group proposed a limited joint settlement to allocate the DWR revenue requirement among the investor-owned utilities (IOUs). This settlement proposes to shift more than $1 billion in additional costs to SDG&E customers and would have a negative impact on customers' commodity costs over the remaining eight-year life of the DWR contracts. On July 19, 2004, the CPUC issued a proposed decision and an alternate decision recommending permanent allocations of DWR contract costs to the IOUs. These proposals were revised and third and fourth alternate decisions were issued on September 9, 2004. None of the proposed or alternate decisions would adopt the settlement; instead, they would permanently allocate a percentage of the fixed or above market costs of the contracts to SDG&E for the remaining life of the contracts (2004-2013). The CPUC is expected to address this matter at its meeting on November 19, 2004.

The judge's proposed decision and Commissioner Lynch's alternate decision would allocate 12.5 percent of the fixed costs of the contracts for the remaining term, resulting in a total shift of $1 billion to SDG&E customers. Commissioner Brown's alternate decision determines SDG&E's share of the above-market costs for all contracts for all years to be 9.9 percent, resulting in a total shift of $787 million. Commissioner Peevey's alternate decision would allocate 10.3 percent of the fixed costs of the contracts to SDG&E, resulting in a total shift of $425 million.

Although these proposed decisions would have no effect on SDG&E's net income, they could adversely affect its customer rates and SDG&E's cash flows. 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, were increased to provide more-contemporaneous recovery. Until January 1, 2006, state law provides SDG&E with a recovery triggering mechanism when an over or undercollection exceeds approximately $30 million. If the triggering mechanism is not extended, the CPUC will have discretion on when to act on over and undercollections.

SDG&E's long-term resource plan identifies the forecasted needs for capacity resources within its service territory to support transmission grid reliability. An updated 10-year resource plan was filed on July 9, 2004, in a CPUC 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 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.

In order to satisfy SDG&E's recognized near-term need for grid reliability and capacity, in May 2003 SDG&E issued a Request for Proposals for the years 2005-2007 for at least 69 MW of electric capacity in 2005 increasing to 291 MW in 2007.

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 a 550-MW plant (Palomar) being developed by SER for completion in 2006), as more fully described in the Annual Report. 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 in the next few months. 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 (Ramco facility) and filed for the Palomar facility in November 2004. The 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 equivalency of purchase power contracts or an equity buildup for construction. These matters may be re-introduced for consideration in future CPUC proceedings.

NATURAL GAS MARKET OIR

The CPUC's Natural Gas Market Order Instituting Rulemaking (OIR) was instituted on January 22, 2004, and will be addressed in two phases. A decision on Phase I was issued on September 2, 2004 and the schedule for Phase II calls for a decision by the end of 2004. Further discussion of Phase I and Phase II is included in the Annual Report. The focus of the Gas OIR is the period from 2006 to 2016. Since Natural Gas Industry Restructuring (GIR), as discussed in the Annual Report, 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 approves the California Utilities' transportation capacity pre-approval procedures with some modifications. SoCalGas' existing pipeline capacity contract with Transwestern Pipeline Company expires in November 2005 and its primary contracts with El Paso Natural Gas Company expire in August 2006. Discussions are underway pursuant to the framework approved by the CPUC to acquire replacement capacity. The Phase I decision also directs the California Utilities to file, by December 2, 2004, an application to implement proposals for transmission system integration, firm access rights, and off-system delivery services. The CPUC has determined that project developers, not the utilities, will be presumed to pay for the costs for access-related infrastructure, subject to 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 FILINGS

In 2002, the California Utilities filed cost of service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs, as further discussed in the Annual Report. The California Utilities requested revenue increases of $101 million. As previously reported, in December 2003 the California Utilities filed with the CPUC proposed settlements of their cost of service proceedings. The settlements, if approved by the CPUC, would reduce the California Utilities' annual rate revenues by an aggregate net amount of approximately $46 million from the rates in effect during 2003. The CPUC's Office of Ratepayer Advocates (ORA) and most other major parties to the cost of service proceedings have recommended that the CPUC approve the settlements.

On September 28, 2004, the CPUC's Administrative Law Judge (ALJ) and the CPUC Commissioner assigned to the cost of service proceedings issued differing proposed decisions for consideration by the CPUC. Both of these proposed decisions recommend that the CPUC reject the proposed settlements. The ALJ's proposed decision would, if adopted by the CPUC, increase annual rate revenues by $60 million from that contemplated by the settlements but would also adopt a one-way balancing account requiring that any reductions in operating labor costs from those estimated in establishing rates be refunded to customers. CPUC Commissioner Wood's alternate proposed decision, which does not include a one-way labor balancing account, would, if adopted by the CPUC, increase the annual rate reduction by an additional $24 million from that contemplated by the proposed settlements.

The company believes that a factual error relating to SDG&E's nuclear electric rate revenues was applied in the proposed decisions of both the ALJ and Commissioner Wood. The company also believes that Commissioner Wood's proposed decision contains a depreciation error with respect to SDG&E. If these errors and other, minor factual errors are corrected, they would increase the annual rate revenues that would be provided by the ALJ's proposed decision to $93 million above that contemplated by the settlements and would increase the annual rate revenues that would be provided by Commissioner Wood's alternative proposed decision to $26 million above that contemplated by the settlements. Both proposed decisions would approve balancing accounts for pension costs similar to those contemplated by the settlements and various other cost balancing accounts not contemplated by the settlements. All the proposals contemplate that the rates resulting from the cost of service proceedings would remain effective through 2007 subject to annual attrition adjustments.

The company previously reported that it expects that another CPUC commissioner will issue an additional proposed decision that, if adopted by the CPUC, would essentially approve the proposed settlements. Subsequently, on October 28, 2004, the CPUC at its regularly scheduled meeting deferred acting on the cost of service proceedings at the request of Commissioner Brown, who stated that he would issue an additional proposed decision.

The CPUC may adopt any one of the proposed decisions or reject all of them and adopt a different outcome. The company expects that a CPUC decision will be issued by year end.

The CPUC previously ordered that any changes in rates resulting from the cost of service proceedings would be effective retroactively to January 1, 2004. Consequently, during 2004 the company and the California Utilities have, in general, recorded revenue and resulting net income in a manner consistent with the reduced rates contemplated by the proposed settlements, except for the favorable effect of the recovery of pension costs contemplated by the proposed settlements and provided by the proposed decisions. To the extent that the revenues provided by the CPUC's decision in the cost of service proceedings differ from those previously recorded, a reconciling adjustment to revenues and resulting net income would be recorded in the latest quarter for which financial statements had not been published.

Other ratemaking issues are included in Phase II of the cost of service proceedings. In addition to recommending changes in the performance-based regulation (PBR) formulas, the 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. On July 21, 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 revenue sharing. The agreement 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. It is not likely that the CPUC will address this matter in its decision related to Phase II of this proceeding before year-end 2004. Consequently, to ensure that the results of Phase II would be applicable for a full year in 2005, SoCalGas and SDG&E filed with the CPUC on September 29, 2004, a petition to modify a prior decision that provided for the differences between 2004's rates and the amounts determined in the cost of service decision to be collected or refunded in future rates, to also apply to similar differences occurring in 2005 prior to implementation of the cost of service decision.

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 applicability of rewards or penalties. As part of the proposed Phase II Settlement Agreement, Revenue 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 revenue sharing mechanism also provides either utility the option to file for suspension of the earnings sharing mechanism if earnings for two consecutive years fall 175 basis points or more below its authorized rate of return; however, if earnings are 300 or more basis points above the utility's authorized rate of return, the revenue 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.

Edison's CPUC decision on its cost of service application sets rates for San Onofre Nuclear Generating Station (SONGS), 20 percent of which is owned by SDG&E. As discussed in the Annual Report, 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 permission to replace SONGS' steam generators, which would increase the total cost of SONGS by an estimated $800 million ($160 million for SDG&E). SDG&E has the option of not participating in the project and has informed Edison of its intention to exercise this option. Doing so would reduce SDG&E's ownership percentage in SONGS by an amount to be determined in arbitration and will be subject to CPUC review and approval. Such approval is expected to occur during late 2005. If the proposed reduction of SDG&E's ownership percentage resulting from the arbitration is unacceptable, SDG&E may elect to participate in the replacement project.

During the current SONGS Unit 3 refueling outage, 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 has reported its intention to move the planned replacement of Unit 3's pressurizer sleeves forward from 2006 to the current outage. This extra work will lengthen the current outage from 55 days to a range of 95 to 110 days, but allows Edison to move the 2006 refueling outage out of the peak summer period to the fall or winter of 2006. Edison has 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 current 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 plans to make repairs during the current 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.

PERFORMANCE-BASED REGULATION

As further described in the Annual Report, under PBR, the CPUC requires future income potential to be tied to achieving or exceeding specific performance and productivity goals, rather than relying solely on expanding utility plant to increase earnings. PBR, demand-side management (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 the nine months ended September 30, 2004 consisted of $6.3 million related to SoCalGas' Year

9 GCIM, which was approved on February 26, 2004 and $1.5 million related to SDG&E's Year 10 natural gas PBR, which was approved on August 22, 2004. These rewards were awarded by the CPUC subject to refund based on the outcome of the Border Price Investigation, as discussed below. The cumulative amount of rewards subject to refund based on the outcome of the Border Price Investigation is $65.1 million, substantially all of which has been included in net income.

At September 30, 2004, the following performance incentives were pending CPUC approval and, therefore, were not included in the company's earnings (dollars in millions):

Program	SoCalGas	SDG&E	Total
DSM/Energy Efficiency*	$ 10.9	$ 37.7	$ 48.6
2003 Distribution PBR	--	8.2	8.2
GCIM/natural gas PBR	2.4	--	2.4
2003 safety	.5	--	.5
Total	$ 13.8	$ 45.9	$ 59.7

* Dollar amounts shown do not include interest, franchise fees or uncollectible amounts.

SOUTHERN CALIFORNIA FIRES

Several major wildfires that began on October 26, 2003 severely damaged SDG&E's infrastructure, causing a significant number of customers to be without utility services. On October 27, 2003, then governor Gray Davis declared a State of Emergency for the State of California. The declaration authorized the establishment of catastrophic event memorandum accounts (CEMA) to record all incremental costs (costs not already included in rates) associated with the repair of facilities and the restoration of service. Incremental electric distribution and natural gas related costs are recovered through the CEMA. Electric transmission related costs are recovered through the annual FERC true-up proceeding. Incremental costs incurred related to the wildfires and recoverable through the CEMA were $38 million.

On June 28, 2004, SDG&E filed its 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 fires. 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 ALJ indicated that he expects to issue a proposed decision by the end of the first quarter of 2005.

SoCalGas did not file a CEMA application as damages incurred as a result of the wildfires were minimal.

COST OF CAPITAL

Effective January 1, 2005, SDG&E's authorized return on rate base (ROR) and return on equity (ROE) will be 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 new benchmark will be 6.19 percent and another 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 given year. If the cost of service proceeding described above is decided by the CPUC along the lines of the settlement, the effect of the changes in ROR and ROE would be to decrease net income in 2005 by $10 million from what it would have been if the rates had not changed. The electric-transmission cost of capital is determined under a FERC proceeding.

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 5.10 percent and the Global Insight forecast was 5.84 percent at September 30, 2004.

BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

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. SoCalGas and SDG&E 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 delayed 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 in the Annual Report, on May 27, 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 of the GIR implementation decision 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 100 percent balancing account protection for SoCalGas' risk on local transmission and distribution revenues from January 1, 2003 until the CPUC issues its next BCAP decision. SoCalGas is seeking to continue this balancing account protection in the Natural Gas OIR proceeding.

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 September 30, 2004, the cumulative amount of shareholder awards, substantially all of which has been included in net income, was $65.1 million. The ORA has filed testimony supporting the GCIM and the actions of SoCalGas during this period. The first phase of this investigation was reopened for one day on October 25, 2004, for additional testimony and supplemental opening and reply briefs. While the ALJ stated that a proposed decision is not imminent, the company expects that a proposed decision will be issued before year end for consideration by the CPUC. Although the proposed decision may be adverse to it, the company believes it is unlikely that the full CPUC would adopt any such adverse decision and would instead conclude that the California Utilities were not responsible for any natural gas price spikes. A final CPUC decision in the first phase of the investigation is not expected until 2005. 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.

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 the 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 an opinion issued May 21, 2004, 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.

RECOVERY OF CERTAIN DISALLOWED TRANSMISSION COSTS

The Federal Court of Appeals scheduled completion of briefing by February 9, 2005, and set oral argument for April 14, 2005, concerning SDG&E's recovery of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink (SWPL) and charges assessed to SDG&E under the California Independent System Operator (ISO) FERC tariff for transmission line losses, and grid management and other charges related to energy schedules of its SWPL co-owners. The parties in the related private arbitration have agreed to hold the arbitration in abeyance pending resolution of the FERC tariff proceeding.

FERC ACTIONS

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 SET, 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 SET is required to provide refunds, they could result in payments by SET after adjusting for any amounts still owed to SET for power supplied during the relevant period (or reduced receipts if refunds are less than amounts owed to SET).

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.

SET previously established reserves for its likely share of the original $1.8 billion discussed above. During the nine months ended September 30, 2004, SET 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.

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 SET and other power suppliers.

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 SET and SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. Second, the FERC directed more than 20 entities, including SET, to show cause why their activities, in partnership or alliance with others, during the period January 1, 2000 to June 20, 2001 did not constitute gaming and/or anomalous market behavior in violation of the tariffs. Remedies for confirmed violations could include disgorgement of profits and revocation of market-based rate authority. The FERC has encouraged the various entities to settle these issues. On October 31, 2003, SET agreed to pay $7.2 million in full resolution of these investigations. That liability was recorded as of December 31, 2003. The SET settlement was approved by the FERC on August 2, 2004. 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.

NOTE 7. CONTINGENCIES

NUCLEAR INSURANCE

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. Detail of the coverage is provided in the Annual Report. As of September 30, 2004, the secondary financial protection provided by the Price-Anderson Act is $10.5 billion if the liability loss exceeds the insurance limit of $300 million. In addition, the maximum SDG&E could be assessed is $8.8 million should there be a retrospective premium call under the risk sharing arrangements of the nuclear property, decontamination and debris removal insurance policy.

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.

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 is stored in the SONGS Units 1, 2 and 3 Spent Fuel Pools (SFP) and the SONGS Independent Spent Fuel Storage Installation (ISFSI). Movement of Unit 1 spent fuel from the Unit 3 SFP to the ISFSI was completed in late 2003. Movement of Unit 1 spent fuel from the Unit 1 SFP to the ISFSI is scheduled to be completed by the end of 2004 and from the Unit 2 SFP to the ISFSI by late 2005. With these moves, there will be sufficient space in the Unit 2 and 3 SFPs to meet plant requirements through mid-2007 and mid-2008, respectively.

ARGENTINE INVESTMENTS

As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent declines in the value of the peso, SEI reduced the carrying value of its Argentine investments downward by a cumulative total of $199 million as of September 30, 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 by the end of 2005 on SEI's arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of SEI'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.

LITIGATION

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. 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, SER was awarded judgment in its favor in the state civil action between SER and the DWR, in which the DWR sought to void its 10-year contract under which the company sells energy 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 SER and, although it has disputed a small percentage of the billings and the manner of certain deliveries, it has paid all amounts that have been billed under the contract. However, the DWR has commenced an arbitration proceeding, disputing SER's performance on various operational matters. Among other proposed remedies, the DWR has requested a declaration by the arbitration panel that SER's performance is inadequate and constitutes a material breach of the agreement permitting it to terminate the contract. SER believes these claims are without merit and has filed a motion to dismiss claims in the arbitration proceeding. Arbitration on any remaining claims will occur in mid-2005.

On June 25, 2003, the FERC issued orders upholding SER's 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 has been scheduled for December 2004, with a decision by the appellate court expected during 2005.

Energy Crisis Litigation

In 2000 and 2001, California experienced a severe energy crisis characterized by dramatic increases in the prices of electricity and natural gas. Many, often duplicative, lawsuits have been filed against numerous energy companies seeking overlapping damages aggregating in the tens of billions of dollars for allegedly unlawful activities asserted to have caused or contributed to the energy crisis. In addition, the energy crisis has generated numerous governmental investigations and regulatory proceedings. The company is cooperating in various investigations, including an investigation being conducted by the California Attorney General into possible anti-competitive behavior. The material regulatory proceedings arising out of the energy crisis that involve the company are briefly summarized, along with other proceedings, in Note 6 and this Note 7. The lawsuits arising out of the energy crisis to which the company is a defendant are briefly 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 Natural Gas Company (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 (including cases involving unrelated claims not applicable to Sempra Energy, SoCalGas or SDG&E) will pay approximately $1.7 billion to resolve these claims. The proceeding against Sempra Energy and the California Utilities has not been settled and continues to be litigated. During the third quarter of 2004, the court denied motions by Sempra Energy and the California Utilities for summary judgment in their favor. Sempra Energy and the California Utilities have requested the Court of Appeal to review these denials; however, such an interim review pending a final decision on the merits of the case is entirely at the discretion of the appellate court. 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. The trial of the case was previously set for September 2004 but has been postponed and the newly assigned judge has yet to schedule a new trial date. (The original judge is retiring at year end.)

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.

In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, including Sempra Energy, the California Utilities and other company subsidiaries, seeking 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, which they have done and Sempra Energy has filed another motion to dismiss, which is scheduled to be heard on November 29, 2004.

In May 2003 and February 2004, antitrust actions against various trade publications and energy companies, including Sempra Energy and SET, alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications and by entering into wash trades, were filed in San Diego Superior Court. Both actions have been 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 SET, among various other entities in San Diego Superior and U.S. District Courts.

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, SET, SoCalGas and SDG&E. Three identical lawsuits were filed in October 2004 in the Alameda and San Mateo Superior Courts.

In August 2003, a lawsuit was filed in the Southern District of New York against Sempra Energy and its subsidiary, Sempra Energy Solutions (SES), 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 of 2003, another suit containing identical allegations was filed and consolidated with the New York action. Subsequently, plaintiffs dismissed Sempra Energy and SES from these cases. On January 20, 2004, plaintiffs filed an amended consolidated complaint that named SET 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 SET 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, SET and SER, 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 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, SER and SET). 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 was 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 them have been filed. In October 2004 another case was filed in Santa Clara Superior Court against SER, 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 the company, SET and SER, by 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.

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. The Supreme Court has not yet determined whether it will grant review.

In May 2003, a federal judge issued an order finding that the Department of Energy's (DOE) environmental assessment of two Mexicali power plants, including SER's Termoelectrica de Mexicali (TDM) plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. In July 2003, the judge ordered the DOE to conduct additional environmental studies and denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE undertook to perform an Environmental Impact Study, which is expected to be completed in December 2004.

The Peruvian appellate court has affirmed the dismissal of the charges against officers of Luz del Sur S.A.A. (Luz del Sur), a company affiliate, and others concerning the price of utility assets acquired by Luz del Sur from the Peruvian government. However, the Peruvian tax authorities continue to claim that Luz de Sur owes additional income taxes related to the disputed valuation. Hearings are scheduled for November 10, 2004.

At September 30, 2004, SET remains due approximately $100 million from energy sales made in 2000 and 2001 through the ISO and the PX markets. The collection of these receivables depends on several factors, including the FERC refund case. The company believes adequate reserves have been recorded.

INCOME TAX ISSUES

Section 29 Income Tax Credits

On July 1, 2004, SEF 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, SEF will not be receiving Section 29 income tax credits in the future.

During the third quarter of 2004, the IRS concluded its examinations of the company's Section 29 income tax credits for certain years, reporting no change in the credits. From acquisition of the facilities in 1998 through December 31, 2003, the company has generated Section 29 income tax credits of $251 million. In addition, the company has generated Section 29 tax credits of $75 million for the nine months ended September 30, 2004, of which $24 million occurred in the third quarter.

If the recent increases in oil prices continue and do not reverse, a partial or complete phase out of Section 29 tax credits may occur in 2005 or in subsequent years in accordance with Section 29 regulations.

NOTE 8. SEGMENT INFORMATION

The company is a holding company, whose subsidiaries are primarily engaged in the energy business. It has four separately managed reportable segments: SoCalGas, SDG&E, SET and SER, which are described in the Annual Report.

The accounting policies of the segments are described in the notes to Consolidated Financial Statements in the Annual Report, and segment performance is evaluated by management based on reported income. There were no significant changes in segment assets during the nine months ended September 30, 2004.

	Three months ended September 30,		Nine months ended September 30,	
(Dollars in millions)	2004	2003	2004	2003
Operating Revenues:				
Southern California Gas	$ 826	$ 794	$ 2,821	$ 2,622
San Diego Gas & Electric	550	667	1,666	1,749
Sempra Energy Trading	355	304	981	832
Sempra Energy Resources	413	234	1,101	453
All other	84	74	215	206
Intersegment revenues	(63)	(15)	(263)	(41)
Total	$ 2,165	$ 2,058	$ 6,521	$ 5,821
Net Income (Loss):				
Southern California Gas*	$ 68	$ 53	$ 174	$ 148
San Diego Gas & Electric*	60	120	140	206
Sempra Energy Trading	44	22	143	39
Sempra Energy Resources	64	33	123	48
All other	(5)	(17)	(31)	(26)
Total	$ 231	$ 211	$ 549	$ 415

* after preferred dividends

ITEM 2.

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

The following discussion should be read in conjunction with the financial statements contained in this Form 10-Q, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in the Annual Report and "Risk Factors" contained in the Form 10-K.

OVERVIEW

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

RESULTS OF OPERATIONS

Net income and operating income for the three months and for the nine months ended September 30, 2004 were up substantially from the corresponding periods of 2003. The following table summarizes the major factors affecting the comparisons for both periods.

	Nine Months		Three Months	
(Dollars in millions)	Operating Income	Net Income	Operating Income	Net Income
Reported amounts for the periods ended September 30, 2003	$ 725	$ 415	$ 307	$ 211
Unusual items in 2003:				
SDG&E power contract settlement	(116)	(65)	(116)	(65)
Impairment of Frontier Energy assets	77	47	77	47
California energy crisis litigation costs and SoCalGas sublease losses	74	43	74	43
SoCalGas' natural gas procurement awards	(48)	(29)	(48)	(29)
Cumulative effect of EITF 02-3 through December 31, 2002	--	29	--	--
SONGS incentive pricing (ended 12/31/03)	(65)	(38)	(18)	(11)
Resolution of vendor disputes in Argentina	--	(11)	--	--
AEG income in 2003 – disposed of in April 2004	--	(2)	--	(7)
	647	389	276	189
Unusual items in 2004:				
Losses of AEG – disposed of in April 2004	--	(32)	--	--
Income tax audit issues	--	18	--	(5)
Resolution of vendor disputes in Argentina	--	12	--	--
Unusual litigation expenses	(16)	(10)	--	--
SoCalGas' gain on sale of partnership property	--	9	--	9
Gain on settlement of Cameron liability	--	8	--	--
Gain on partial sale of Luz del Sur	--	5	--	--
Operations (2004 compared to 2003)	266	150	69	38
Reported amounts for the periods ended September 30, 2004	$ 897	$ 549	$ 345	$ 231

California Utility Revenues and Cost of Sales

Natural gas revenues increased to $3.2 billion for the nine months ended September 30, 2004 from $3.0 billion for the corresponding period in 2003, and the cost of natural gas increased to $1.7 billion in 2004 from $1.5 billion in 2003. Additionally, natural gas revenues were $909 million for the quarter ended September 30, 2004 compared to $870 million for the corresponding period in 2003, and the cost of natural gas was $438 million in 2004 compared to $372 million in 2003. These increases were primarily attributable to natural gas cost increases, which are passed on to customers, offset by $55 million and $48 million, respectively, of approved performance awards recognized during the nine-month and three-month periods ended September 30, 2003.

Electric revenues decreased to $1.2 billion for the nine months ended September 30, 2004 from $1.4 billion for the same period in 2003, and the cost of electric fuel and purchased power decreased to $425 million in 2004 from $428 million in 2003. Additionally, electric revenues decreased to $445 million for the quarter ended September 30, 2004 from $576 million for the same period in 2003, and the cost of electric fuel and purchased power increased to $143 million in 2004 from $128 million in 2003. The decreases in revenues were due to the recognition of $116 million related to the approved settlement of intermediate-term purchase power contracts in the third quarter of 2003, more power being provided to SDG&E's customers by the DWR in 2004 as discussed in Note 6 of the notes to Consolidated Financial Statements, and higher earnings from PBR awards in 2003. The decrease in the cost of electric fuel and purchased power for the nine-month period was mainly due to more power being provided by the DWR, while the increase for the three-month period was due to higher electric commodity costs partially offset by more power being provided by the DWR. Under the current regulatory framework, changes in commodity costs normally do not affect net income.

Performance awards are discussed in Note 6 of the notes to Consolidated Financial Statements.

In 2002, the California Utilities filed Cost of Service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs, as further discussed in the Annual Report and in Note 6 of the notes to Consolidated Financial Statements. In accordance with generally accepted accounting principles, the California Utilities are generally recognizing 2004 revenue in a manner consistent with the reduced rates contemplated by the proposed settlements, except for the favorable effect of the recovery of pension costs contemplated by the proposed settlements and provided by both proposed decisions. To the extent that the revenues provided by the CPUC's decision in the cost of service proceedings differ from those previously recorded, a reconciling adjustment to revenues and resulting net income would be recorded in the latest quarter for which financial statements had not been published. To date, the impacts of accounting consistent with the settlement have not had a material effect on the financial statements.

The tables below summarize the natural gas and electric volumes and revenues by customer class for the nine months ended September 30, 2004 and 2003.

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

	Gas Sales		Transportation & Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
<s>	<c>	<c>	<c>	<c>	<c>	<c>
2004:						
Residential	197	$ 1,943	1	$ 5	198	$ 1,948
Commercial and industrial	91	718	207	141	298	859
Electric generation plants	--	--	190	67	190	67
Wholesale	--	--	13	5	13	5
	288	$ 2,661	411	$ 218	699	2,879
Balancing accounts and other						310
Total						$ 3,189
2003:						
Residential	189	$ 1,767	1	$ 5	190	$ 1,772
Commercial and industrial	90	649	209	138	299	787
Electric generation plants	--	3	186	61	186	64
Wholesale	--	--	14	2	14	2
	279	$ 2,419	410	$ 206	689	2,625
Balancing accounts and other						336
Total						$ 2,961

</table>

<table>
Electric Distribution and Transmission
(Volumes in millions of kilowatt hours, dollars in millions)
<caption>

	2004		2003	
	Volumes	Revenue	Volumes	Revenue
<s>	<c>	<c>	<c>	<c>
Residential	5,242	$ 518	4,988	$ 561
Commercial	4,960	487	4,681	526
Industrial	1,533	98	1,460	125
Direct access	2,560	77	2,456	62
Street and highway lighting	71	8	68	8
Off-system sales	--	-	26	1
	14,366	1,188	13,679	1,283
Balancing accounts and other		58		85
Total		$ 1,246		$ 1,368

</table>

Although commodity-related revenues from the DWR's purchasing of SDG&E's net short position or from the DWR's allocated contracts are not included in revenue, the associated volumes and distribution revenue are included herein.

Beginning in 2004, off-system sales are accounted for as a reduction of the cost of purchased power.

Other Operating Revenues

Other operating revenues, which consist primarily of revenues at Global, increased to $2.1 billion for the nine months ended September 30, 2004 from $1.5 billion for the same period of 2003, and increased to $811 million for the quarter ended September 30, 2004 from $612 million for the same period of 2003. These increases were primarily due to higher revenues at SER resulting from increased volumes of power sales under the DWR contract and higher revenues at SET resulting from increased commodity revenue, particularly from metals and petroleum.

Other Cost of Sales

Other cost of sales, which consists primarily of cost of sales at Global, increased to $1.2 billion for the nine months ended September 30, 2004 from $886 million for the same period of 2003, and increased to $484 million for the quarter ended September 30, 2004, from $371 million for the same period in 2003. The increases were primarily due to costs related to the higher sales volume for SER as noted above.

Other Operating Expenses

Other operating expenses were $1.6 billion for the nine-month periods ended September 30, 2004 and 2003, including $1.1 billion in both 2004 and 2003 related to the California Utilities. Other operating expenses decreased to $530 million for the quarter ended September 30, 2004 from $668 million for the same period in 2003, including $351 million and $423 million in 2004 and 2003, respectively, related to the California Utilities. The overall change was primarily due to lower costs at SEI mainly due to a $77 million before-tax write-down of the carrying value of the assets of Frontier Energy in the third quarter of 2003. Additionally, there were lower costs at the California Utilities, primarily as a result of a $74 million before-tax charge in the third quarter of 2003 for litigation and for losses associated with a sublease of portions of the SoCalGas headquarters building. These decreases were offset by higher operating costs at SET related to increased trading activity in 2004, the new SER generating plants coming on line and litigation expenses in 2004.

Other Income - Net

Other income, which primarily consists of equity earnings from unconsolidated subsidiaries and interest on regulatory balancing accounts, increased to $58 million for the nine months ended September 30, 2004 from $38 million for the same period of 2003, and increased to $40 million for the quarter ended September 30, 2004 from $34 million for the same period of 2003. The increases were due to the $15 million before-tax gain at SoCalGas from the sale of partnership property, lower equity losses at SEF and increased equity earnings at SER resulting from the acquisition of the Coleto Creek coal plant, offset partially by decreased equity earnings at SEI. In addition, the nine-month period was impacted by 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 $7 million before-tax at SEI from the partial sale of Luz del Sur in 2004.

Interest Income

Interest income increased to $58 million for the nine months ended September 30, 2004 from $30 million for the same period of 2003, and increased to $25 million for the quarter ended September 30, 2004 from $8 million for the same period of 2003. The changes were due primarily to interest on income tax receivables during the first and third quarters of 2004.

Interest Expense

Interest expense increased to $234 million for the nine months ended September 30, 2004 from $223 million for the same period of 2003 due primarily to the reclassification of preferred dividends on mandatorily redeemable trust preferred securities and preferred stock of subsidiaries to interest expense as a result of the adoption on July 1, 2003 of SFAS 150, *Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity,* as well as higher capitalized interest at SER in 2003.

Income Taxes

Income tax expense increased to $191 million for the nine months ended September 30, 2004 from $109 million for the same period of 2003. The corresponding effective income tax rates were 24.7 percent and 19.7 percent, respectively. Additionally, income tax expense increased to $103 million for the third quarter of 2004 compared to $58 million for the third quarter of 2003, and the effective income tax rate increased to 30.6 percent in 2004 from 21.6 percent in 2003. The changes were due primarily to higher taxable income and the resulting higher effective income tax rate in 2004, despite the reduction in estimated income tax liabilities for certain prior years. Discussion of Section 29 income tax credits is provided in Note 7 herein and in Note 7 of the notes to Consolidated Financial Statements of the Annual Report.

Discontinued Operations

During the first quarter of 2004, Sempra Energy's Board of Directors approved management's plan to dispose of the company's interest in AEG. On April 27, 2004, the company disposed of AEG at a $2 million loss net of income taxes. Including the $2 million loss on disposal, AEG's losses were $32 million for the nine months ended September 30, 2004. Note 4 of the notes to Consolidated Financial Statements herein provides further details.

During 2003, the company accounted for its investment in AEG under the equity method of accounting. As such, for the nine-month and three-month periods ended September 30, 2003, the company recorded its share of AEG's net income, $1 million and $7 million, respectively, in Other Income – Net on the Statements of Consolidated Income. Additionally, for the nine-month and three-month periods the company recorded $2 million and $1 million, respectively, of interest income and for both periods the company recorded offsetting income tax expense of $1 million. Effective December 31, 2003, AEG was consolidated as a result of the adoption of FIN 46. This is discussed further in Note 2 herein and in Note 1 of the Annual Report.

Net Income

Net income for the nine months ended September 30 increased to $549 million, or $2.36 per diluted share of common stock in 2004 from $415 million, or $1.98 per diluted share in 2003. Net income for the third quarter was $231 million, or $0.98 per diluted share for 2004, compared to $211 million or $1.00 per diluted share in 2003. Unusual items affecting these comparisons are provided in the first table in this section. Although net income increased for both periods, earnings per share were affected by the issuance of 16.5 million additional shares in the fourth quarter of 2003 and the effect on the Equity Units of the change in the market price of company stock.

<table>
Net Income by Business Unit
<caption>

(Dollars in millions)	Three months ended September 30, 2004	Three months ended September 30, 2003	Nine months ended September 30, 2004	Nine months ended September 30, 2003
<s>	<c>	<c>	<c>	<c>
California Utilities				
Southern California Gas Company	$ 68	$ 53	$ 174	$ 148
San Diego Gas & Electric	60	120	140	206
Total Utilities	128	173	314	354
Global Enterprises				
Sempra Energy Trading	44	22	143	67
Sempra Energy Resources	64	33	123	48
Sempra Energy International	7	(32)	35	(7)
Sempra Energy LNG	(4)	--	--	--
Sempra Energy Solutions	1	--	1	8
Total Global Enterprises	112	23	302	116
Sempra Energy Financial	10	13	26	32
Parent and other	(19)	2	(61)	(58)
Continuing operations	231	211	581	444
Discontinued operations	--	--	(32)*	--
Cumulative effect of change in accounting principle	--	--	--	(29)**
Consolidated net income	$ 231	$ 211	$ 549	$ 415

* Includes ($2) million related to the loss on disposal of AEG.
** The effects were ($28) million at SET and ($1) million at SES.
</table>

Subsequent to September 30, 2004, SES will be reorganized such that its commodity business will be moved to SET and its other businesses will be moved to SER.

SOUTHERN CALIFORNIA GAS COMPANY

SoCalGas recorded net income of $174 million and $148 million for the nine-month periods ended September 30, 2004 and 2003, respectively, and net income of $68 million and $53 million for the quarters ended September 30, 2004 and 2003, respectively. The increases were primarily due to the $32 million after-tax charge for litigation and for losses associated with a long-term sublease of portions of its headquarters building in 2003, higher margins in 2004 and the gain on the sale of partnership property, partially offset by higher GCIM awards in 2003 and higher depreciation expense in 2004.

SAN DIEGO GAS & ELECTRIC COMPANY

SDG&E recorded net income of $140 million and $206 million for the nine-month periods ended September 30, 2004 and 2003, respectively, and net income of $60 million and $120 million for the quarters ended September 30, 2004 and 2003, respectively. The decreases were primarily due to income of $65 million after-tax in 2003 related to the approved settlement of intermediate-term purchase power contracts, the 2003 Incremental Cost Incentive Pricing for SONGS, higher performance awards in 2003 and higher depreciation expense in 2004 partially offset by higher electric transmission and distribution revenues (excluding the effects of the settlement, which are included in Revenues) in 2004, and by higher operating expenses in 2003 including litigation charges in the third quarter.

SEMPRA ENERGY TRADING

SET recorded net income of $143 million and $67 million for the nine-month periods ended September 30, 2004 and 2003, respectively, excluding the cumulative effect of the change in accounting principle of ($28) million in 2003. Additionally, SET recorded net income of $44 million and $22 million for the quarters ended September 30, 2004 and 2003, respectively. The increases were primarily attributable to higher trading margins, particularly on metals and petroleum, partially offset by litigation expenses. Net income for the third quarter of 2004 was $38 million lower than the true economic value of SET's activities due to timing differences between economic valuations and accounting principles. It is expected that most of that deferred income will be recognized in the fourth quarter of 2004.

A summary of SET's unrealized revenues for trading activities for the nine months ended September 30, 2004 and 2003 follows:

(Dollars in millions)	2004	2003
Balance at beginning of period	$ 269	$ 180
Cumulative effect adjustment	--	(48)
Additions	710	833
Realized	(189)	(552)
Balance at end of period	$ 790	$ 413

The estimated fair values for SET's trading activities as of September 30, 2004, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

<table>
<caption>

Source of fair value	Fair Market Value at September 30, 2004	/--Scheduled Maturity (in months)--/ 0-12	13-24	25-36	>36
<S>	<C>	<C>	<C>	<C>	<C>
Prices actively quoted	$ 623	$ 548	$ 50	$ (1)	$ 26
Prices provided by other external sources	1	(9)	--	--	10
Prices based on models and other valuation methods	(22)	(33)	--	--	11
Over-the-counter revenue *	602	506	50	(1)	47
Exchange contracts **	188	249	(58)	(1)	(2)
Total	$ 790	$ 755	$ (8)	$ (2)	$ 45

* The present value of unrealized revenue to be received or (paid) from outstanding OTC contracts.
** Cash (paid) or received associated with open exchange contracts.
</table>

SET's Value at Risk (VaR) amounts are described in Item 3.

The CPUC prohibits the California Utilities and the other IOUs from procuring electricity from their affiliates. This is discussed in "Electric Industry Regulation" in Note 13 of the Annual Report.

SEMPRA ENERGY RESOURCES

SER recorded net income of $123 million and $48 million for the nine-month periods ended September 30, 2004 and 2003, respectively, and net income of $64 million and $33 million for the quarters ended September 30, 2004 and 2003, respectively. The increased earnings in 2004 were primarily due to higher volumes of power sales under the DWR contract.

SEMPRA ENERGY INTERNATIONAL

SEI recorded net income of $35 million for the nine-month period ended September 30, 2004 compared to a net loss of $7 million for the same period of 2003, and recorded net income of $7 million for the quarter ended September 30, 2004 compared to a net loss of $32 million for the same period of 2003. The increases for both periods were due to the 2003 charge recorded to write down the carrying value of assets at Frontier Energy, as previously discussed, and increased earnings from the company's Gasoducto Bajanorte natural gas pipeline in 2004. Additionally, the increase for the nine-month period was due to a gain on the sale of a portion of SEI's interests in Luz del Sur, a Peruvian electric utility, offset by the impact of changes in estimates for certain income tax issues in the second quarter of 2004.

SEMPRA ENERGY LNG

SELNG recorded break-even results for the nine months ended September 30, 2004 and a net loss of $4 million for the quarter ended September 30, 2004. For the nine-month period, the income from 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) was offset by start-up costs. The loss for the three-month period was due to the start-up costs.

SEMPRA ENERGY SOLUTIONS

SES recorded net income of $1 million and $8 million for the nine-month periods ended September 30, 2004 and 2003, respectively, excluding the cumulative effect of the change in accounting principle of ($1) million in 2003. Additionally, SES recorded net income of $1 million for the quarter ended September 30, 2004 compared to break-even results for the same period of 2003. The decrease for the nine-month period was primarily due to lower net commodity revenues.

SEMPRA ENERGY FINANCIAL

SEF recorded net income of $26 million and $32 million for the nine-month periods ended September 30, 2004 and 2003, respectively, and net income of $10 million and $13 million for the quarters ended September 30, 2004 and 2003, respectively. During the third quarter of 2004, SEF 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, SEF will not be recognizing Section 29 income tax credits in the future.

PARENT AND OTHER

Net losses for Parent and Other were $61 million and $58 million for the nine-month periods ended September 30, 2004 and 2003. Additionally, net losses were $19 million for the quarter ended September 30, 2004, compared to net income of $2 million for the same period of 2003. The change for the quarter was due primarily to a lower 2003 income tax expense as a result of a positive adjustment to reflect the company's consolidated effective tax rate.

CAPITAL RESOURCES AND LIQUIDITY

The company's California Utility operations are the major source of liquidity. Funding of other business units' capital expenditures is significantly dependent on the California Utilities' paying sufficient dividends to Sempra Energy and on SET's liquidity requirements, which fluctuate significantly.

At September 30, 2004, the company had $267 million in cash and $3.3 billion in available unused, committed lines of credit. See "Cash Flows from Financing Activities" for discussion on changes in credit facilities in 2004.

Management believes these amounts and cash flows from operations and new security issuances will be adequate to finance capital expenditure requirements, shareholder dividends, any new business acquisitions or start-ups, and other commitments. If cash flows from operations were to be significantly reduced or the company were to be unable to issue new securities on acceptable terms, neither of which is considered likely, the company would be required to reduce non-utility capital expenditures and investments in new businesses. Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activities in a manner consistent with its intention to maintain strong, investment-quality credit ratings. 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 debt 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 plans to purchase (in 2006) from SER a 550-MW 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.

SET provides or requires cash as the level of its net trading assets fluctuates with prices, volumes, margin requirements (which are substantially affected by credit ratings and commodity price fluctuations) and the length of its various trading positions. Its status as a source or use of cash also varies with its level of borrowing from its own sources. SET's intercompany borrowings were $618 million at September 30, 2004, up from $359 million at December 31, 2003. SET's external debt was $145 million at September 30, 2004. Company management continuously monitors the level of SET's cash requirements in light of the company's overall liquidity.

SER's projects are expected to be financed through a combination of project financing, SER's cash from operations and borrowings, and funds from the company.

SEI is expected to require funding from the company and/or external sources to continue the expansion of its existing natural gas distribution operations in Mexico and its planned development of pipelines to serve LNG facilities expected to be developed in Baja California, Mexico; Louisiana; and Texas, as discussed in "Cash Flows From Investing Activities," below.

SELNG will require funding for its planned development of LNG receiving facilities. While funding from the company is expected to be adequate for these requirements, the company may decide to use project financing if that is believed to be advantageous.

In the longer term, SEF is expected to again be a net provider of cash through reductions of consolidated income tax payments resulting from its investments in affordable housing. 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 $493 million and $923 million for the nine months ended September 30, 2004 and 2003, respectively. The change was attributable to an increase in net trading assets in 2004 compared to a decrease in 2003, partially offset by higher net income and a higher decrease in accounts receivable in 2004.

For the nine months ended September 30, 2004, the company made pension plan and other postretirement benefit plan contributions of $10 million and $44 million, respectively.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $294 million and $887 million for the nine months ended September 30, 2004 and 2003, respectively. The change was primarily attributable to proceeds from the sale of U.S. Treasury obligations which previously securitized the Mesquite synthetic lease. The collateral was no longer necessary as SER bought out the lease in January 2004. The decrease in cash used in investing activities was also due to lower investments primarily as a result of completion of the Elk Hills and Mesquite power plants. In addition, the company had proceeds of $137 million from the disposal of AEG's discontinued operations.

On April 1, 2004, SEI and PSEG Global, an unaffiliated company, sold a portion of their interests in Luz del Sur for a total of $62 million. Each party had a 44-percent interest in Luz del Sur prior to the sale compared to a 38-percent interest after the sale was completed. SEI recognized an after-tax gain of $5 million as a result of the sale.

Starting in 2003 and through the end of the third quarter of 2004, SET has spent $87 million related to the development of Bluewater Gas Storage, LLC. SET owns the rights to develop the facility and to utilize its capacity to store natural gas for customers who buy, sell or transport natural gas to Michigan. The market-based-pricing facility started injecting natural gas during the second quarter of 2004.

On April 16, 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. This facility, operating as the Pine Prairie Energy Center, will consist of three salt caverns with a total capacity of 24 billion cubic feet (bcf) of natural gas and is expected to begin operations in 2006 and to cost approximately $175 million. The company is currently negotiating contracts to sell the capacity of this facility. FERC approval for the construction and operation of the facility is pending.

On July 20, 2004, the company announced that it had acquired the rights to develop a salt-cavern natural gas storage facility located in Calcasieu Parish, Louisiana, called "Liberty," that is expected to have capacity of 17 bcf.

On April 21, 2004, SELNG announced plans to develop and construct a new $600 million LNG receiving terminal near Port Arthur, Texas. The terminal would be capable of processing 1.5 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, SELNG signed a sale and purchase agreement with British Petroleum and its partners for the supply of 500 million cubic feet of gas a day from Indonesia's Tangguh LNG liquefaction facility to Energia Costa Azul, a planned SELNG regasification terminal in Baja California that is expected to be fully operational in 2008 and to cost between $900 million and $1 billion, including related pipeline costs, of which $50 million had been expended through September 30, 2004. The 20-year agreement provides for pricing tied to the Southern California border index for natural gas and will cover half the capacity of the Energia Costa Azul receipt facility. Also in October 2004, SELNG entered into an agreement with Shell International Gas Limited (Shell) by which Shell has purchased half of the initial capacity of the Energia Costa Azul terminal for an initial period of 20 years. This replaces a prior arrangement that contemplated that Shell would have a 50% equity interest in the terminal.

On July 1, 2004, Topaz Power Partners (Topaz), a 50/50 joint venture between Sempra Energy Partners and Carlyle/Riverstone acquired ten Texas power plants from 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 associated with the plants, initially estimated at $63 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.

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, with a weighted-average life of 4.3 years, for 572 MW of Coleto Creek Power Station's capacity.

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, believes that the fair value of the guarantee is immaterial. The allocation of the purchase price remains subject to adjustment until June 30, 2005.

The company expects to make capital expenditures and investments of $1.2 billion in 2004, of which $852 million had been expended as of September 30, 2004. Significant capital expenditures and investments are expected to include $750 million for California utility plant improvements, $130 million for the Palomar plant and $100 million for the development of LNG regasification terminals. These expenditures and investments are expected to be financed by cash flows from operations and security issuances.

In September 2004, the CPUC approved a proposed framework for the contracting of interstate pipeline capacity for core customers. Discussions are underway for the California Utilities to acquire pipeline capacity to replace capacity contracts expiring over the next two years. The CPUC also approved requests to establish receipt points to accept new supplies, including imported LNG, to the California Utilities' service area. Approval for a point of receipt to import natural gas from Mexico to Southern California via pipelines at Otay Mesa was also obtained. As a result, the California Utilities expect to install capital facilities starting in 2005, in order to receive natural gas supplies from new delivery locations. The CPUC has determined that project developers, not the utilities, will be presumed to pay for the costs for access-related infrastructure, subject to future applications to be filed when more is known about the particular projects. Note 6 of the notes to Consolidated Financial Statements herein provides further details.

Under terms of a franchise agreement and Memorandum of Understanding reached in October 2004 between SDG&E and the City of Chula Vista, SDG&E has committed to support at the CPUC for undergrounding a part of the proposed Otay Mesa transmission line through Chula Vista's bayfront, upon CPUC approval of a substation upgrade, and replacement of certain other overhead transmission lines with underground facilities. Other transmission lines are to be undergrounded pursuant to the tariff Rule 20A undergrounding program. If the Otay Mesa undergrounding project is approved by the CPUC, SDG&E's expected share of cost will be $36 million. If SDG&E does not complete the undergrounding project by April 2010, there will not be an automatic renewal of the franchise at the end of the initial ten-year term.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash used in financing activities totaled $364 million and $80 million for the nine months ended September 30, 2004 and 2003, respectively. The change was due to higher long-term debt payments, partially offset by an increase in long-term debt issuances and a net increase in short-term debt in 2004.

In July 2004, 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 SER. Global continues to have 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.

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. Borrowings under the credit agreement, none of which are outstanding, are available to provide loans to Global and would bear interest at rates varying with market rates, PE's credit ratings and amounts borrowed. The borrowings would be guaranteed by the company and would be subject to mandatory repayment if the company's or SoCalGas' ratio of debt to total capitalization (as defined in the agreement) were to exceed 65%, or if there were to be a change in law materially and adversely affecting SoCalGas' ability to pay dividends or make other distributions to PE.

At September 30, 2004 outstanding extensions of credit under SET's $1 billion credit facility totaled $350 million. Details concerning this credit facility are provided in the Form 10-Q for the six-month period ended June 30, 2004.

SER's energy contracts typically contain collateral requirements related to credit lines. The collateral arrangements provide for SER and/or the counterparty to post cash, guarantees or letters of credit to the other party for exposure in excess of established thresholds. SER may be required to provide collateral when market price movements adversely affect the counterparty's cost of alternative energy should SER fail to deliver the contracted amounts. As of September 30, 2004, SER had outstanding collateral requirements under these contracts of $171 million.

FACTORS INFLUENCING FUTURE PERFORMANCE

Base results of the company in the near future will depend primarily on the results of the California Utilities, while earnings growth and variability will result primarily from activities at SET, SER, SELNG and SEI. Notes 6 and 7 of the notes to Consolidated Financial Statements herein and Notes 13 through 15 of the Annual Report describe events in the deregulation of California's electric and natural gas industries and various FERC, SET and income tax issues.

California Utilities

Note 6 of the notes to Consolidated Financial Statements contains discussions of electric and natural gas restructuring and rates, the pending cost of service proceedings and the CPUC's investigation of compliance with affiliate rules.

Sempra Energy Global Enterprises

Electric-Generation Assets

As discussed in more detail in "Cash Flows From Investing Activities," the company is involved in the expansion of its electric-generation capabilities, including the AEP-related acquisition noted above, which will significantly impact 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.

SELNG is in the process of developing Energia 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. The viability and 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, and completing cost-effective construction of the required facilities. In October 2004, SELNG signed a sale and purchase agreement with British Petroleum for the supply of 500 million cubic feet of gas a day from Indonesia's Tangguh LNG liquefaction facility to Energia Costa Azul that is expected to cost between $900 million and $1 billion, including related pipeline costs, of which $50 million had been expended through September 30, 2004. Also in October 2004, SELNG entered into a 20-year agreement with Shell by which Shell has purchased half of the initial capacity of the Energia Costa Azul terminal. Additional information regarding these activities is provided above in "Cash Flows From Investing Activities."

Beginning in 2003, the company started expanding its natural gas storage capacity by developing Bluewater Gas Storage, LLC. 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 a salt-cavern gas storage facility located in Calcasieu Parish, Louisiana, called "Liberty." Additional information regarding these activities is provided above in "Cash Flows From Investing Activities."

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 Note 7 of the notes to Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND KEY NON-CASH PERFORMANCE INDICATORS

There have been no significant changes to the accounting policies viewed by management as critical or key non-cash performance indicators for the company and its subsidiaries, as set forth in the Annual Report.

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had a significant effect on the company are SFAS Nos. 132 (revised 2003), 143, 149 and 150, FASB Staff Position 106-2, FIN 45 and 46, and the rescission of EITF 98-10, as discussed in Note 2 of the notes to Consolidated Financial Statements. Pronouncements that have or are likely to have a material effect on future earnings 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 by the release of Issue 02-3, the company no longer marks to market energy-related contracts unless the contracts meet the requirements stated under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities,* and SFAS 149, *Amendment of*

Statement 133 on Derivative Instruments and Hedging Activities. A substantial majority of the company's contracts do meet these requirements. 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":* 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 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. Further discussion is provided in Note 2 of the notes to Consolidated Financial Statements.

In June 2004, the FASB issued a proposed interpretation of SFAS 143, *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. The proposed interpretation would be effective for the company on December 31, 2005.

SFAS 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities*": SFAS 149 amends and clarifies accounting for derivative instruments and for hedging activities under SFAS 133. Under SFAS 149, natural gas forward contracts that are subject to unplanned netting do not qualify for the normal purchases and normal sales exception, whereby derivatives are not required to be marked to market when the contract is usually settled by the physical delivery of natural gas. The company has determined that all natural gas contracts are subject to unplanned netting and as such, these contracts are marked to market. In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 are further marked to market. Implementation of SFAS 149 on July 1, 2003 did not have a material impact on reported net income.

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

Adoption of FIN 46 on December 31, 2003 resulted in the consolidation of two VIEs for which Sempra Energy 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 bought out the lease in January 2004.) The other VIE relates to the investment in AEG. Sempra Energy consolidated these entities in its financial statements at December 31, 2003. During the first quarter of 2004, Sempra Energy's Board of Directors approved management's plan to dispose of AEG. Note 4 of the notes to Consolidated Financial

Statements provides further discussion on this matter and the disposal of AEG, which occurred in April 2004.

In accordance with FIN 46, the company has deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003.

Further discussion regarding FIN 46 is provided in Note 2 of the notes to Consolidated Financial Statements.

ITEM 3. **QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

There have been no significant changes in the risk issues affecting the company subsequent to those discussed in the Annual Report.

The VaR for SET at September 30, 2004, and the average VaR for the nine months ended September 30, 2004, at the 95-percent and 99-percent confidence intervals (one-day holding period) were as follows (in millions of dollars):

	95%	99%
At September 30, 2004	$ 7.2	$ 10.2
Average for the nine months ended September 30, 2004	$ 6.9	$ 9.7

As of September 30, 2004, the total VaR of the California Utilities' and SES's positions was not material.

ITEM 4. **CONTROLS AND PROCEDURES**

The company has designed and maintains disclosure controls and procedures to ensure that information required to be disclosed in the company's reports under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and is accumulated and communicated to the company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating these controls and procedures, management recognizes that any system of controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired objectives and necessarily applies judgment in evaluating the cost-benefit relationship of other possible controls and procedures. In addition, the company has investments in unconsolidated entities that it does not control or manage and, consequently, its disclosure controls and procedures with respect to these entities are necessarily substantially more limited than those it maintains with respect to its consolidated subsidiaries.

Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, the company evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures as of September 30, 2004, the end of the period covered by this report. Based on that evaluation, the company's Chief Executive Officer and Chief Financial

Officer concluded that the company's disclosure controls and procedures were effective at the reasonable assurance level.

There has been no change in the company's internal controls over financial reporting during the company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the company's internal controls over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. **LEGAL PROCEEDINGS**

SDG&E and the County of San Diego are continuing to negotiate the remaining terms of a settlement relating to alleged environmental law violations by SDG&E and its contractors in connection with the abatement of asbestos-containing materials during the demolition of a natural gas storage facility that was completed in 2001. The expected settlement would involve payments by SDG&E of less than $750,000.

Except as described above and in Notes 6 and 7 of the notes to Consolidated Financial Statements herein, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

ITEM 5. **OTHER INFORMATION**

The company currently anticipates that its 2005 Annual Meeting of Shareholders will be held on April 5, 2005. Any shareholder satisfying the Securities and Exchange Commission's eligibility requirements who wishes to submit a proposal to be included in the proxy statement for the annual meeting should do so in writing to the Corporate Secretary, 101 Ash Street, San Diego, California 92101-3017.

As a consequence of having advanced the date of the annual meeting by 32 days from the date of the previous annual meeting, Securities and Exchange Commission rules provide that the new deadline for the company's receipt of shareholder proposals for inclusion in the proxy statement is a reasonable time before the company begins to print and mail proxy materials for the annual meeting. The company will regard any proposals that it receives on or before November 19, 2004 (the previously published deadline and that which would have been applicable if the annual meeting date had not been advanced by more than 30 days) as having been timely received. Any such proposals received after November 19, will be regarded as untimely and will not be considered for inclusion in the proxy statement.

Shareholders who wish to present other business, including director nominations, for consideration at the 2005 Annual Meeting must notify the Corporate Secretary of their intention to do so during the period beginning on January 4, 2005 and ending on March 5, 2005. The notice must also provide the information required by the company's bylaws.

ITEM 6. **EXHIBITS AND REPORTS ON FORM 8-K**

(a) Exhibits

Exhibit 10 - Material Contracts

Compensation

10.1 Sempra Energy Employee Stock Incentive Plan

10.2 Sempra Energy Amended and Restated Executive Life Insurance Plan

10.3 Sempra Energy Excess Cash Balance Plan

10.4 Form of Sempra Energy 1998 Long Term Incentive Plan Performance-Based Restricted Stock Award

10.5 Form of Sempra Energy 1998 Long Term Incentive Plan Nonqualified Stock Option Agreement

10.6 Form of Sempra Energy 1998 Non-Employee Directors' Stock Plan Nonqualified Stock Option Agreement

10.7 Sempra Energy Supplemental Executive Retirement Plan

10.8 Neal Schmale Restricted Stock Award Agreement

10.9 Severance Pay Agreement between Sempra Energy and Donald E. Felsinger

10.10 Severance Pay Agreement between Sempra Energy and Neal Schmale

10.11 Sempra Energy Executive Personal Financial Planning Program Policy Document

Exhibit 12 - Computation of ratios

12.1 Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.

Exhibit 31 -- Section 302 Certifications

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

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

Exhibit 32 -- Section 906 Certifications

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

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

(b) Reports on Form 8-K

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

Current Report on Form 8-K filed August 5, 2004, filing as an exhibit Sempra Energy's press release of August 5, 2004, giving the financial results for the quarter ended June 30, 2004.

Current Report on Form 8-K filed September 30, 2004, announcing proposed decisions issued by the CPUC's Administrative Law Judge and the Assigned CPUC Commissioner on September 28, 2004, in the California Utilities' Cost of Service Proceedings.

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

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

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SEMPRA ENERGY

(Registrant)

Date: November 4, 2004

By: /s/ F. H. Ault

F. H. Ault
Sr. Vice President and Controller